EXHIBIT 1 p
Part 1 of 2
5-CE-138
10/19/2009 (aff)

PSC REF#:111634

Public Service Commission of Wisconsin
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April 2, 2009

<u>FILED ELECTRONICALLY</u>

Ms. Sandra J. Paske
Secretary to the Commission
Public Service Commission of Wisconsin
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

RE: Joint Application of Wisconsin Power and Light Company, Wisconsin Public Service Corporation, And Madison Gas and Electric Company for a Certificate of Authority to install Emissions Reduction Systems at the Columbia Energy Center Units 1 and 2 — **Docket No. 5-CE-138**

Dear Secretary Paske:

Wisconsin Power and Light Company, Wisconsin Public Service Corporation, and Madison Gas and Electric Company respectfully and jointly submit the attached Application for Certificate of Authority to install Emissions Reduction Systems at the Columbia Energy Center Units 1 and 2 for the Commission's consideration. Furthermore, we respectfully request that the Commission, upon completion of its review, approve the proposed project and issue a Certificate of Authority.

Thank you for your consideration.

Sincerely,

<u>/s/ Scott R. Smith</u>
Scott R. Smith
Director, Regulatory Relations
Alliant Energy

Enclosure
cc:

Certificate of Authority Application
Columbia Energy Center Units 1 and 2
Emissions Reduction Project

Project Description and Justification

Wisconsin Power and Light Company
Wisconsin Public Service Corporation
Madison Gas & Electric Company

March 31, 2009
Final

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FIGURES AND TABLES

ACRONYMS AND ABBREVIATIONS

ACFM – Actual Cubic Feet per Minute
ACI – Activated Carbon Injection
AFUDC – Allowance for Funds Used During Construction
BART – Best Available Retrofit Technology
BH - Baghouse
BMP – Best Management Practice
CA – Certificate of Authority
CAA – Clean Air Act
CACP – Clean Air Compliance Program
CAIR – Clean Air Interstate Rule
CAVR – Clean Air Visibility Rule
CFB – Circulating Fluidized Bed
CO – Carbon Monoxide
CO_2 – Carbon Dioxide
COHPAC – Compact Hybrid Particulate Collector (baghouse)
CWIP – Construction Work In Progress
DCS – Distributed Control System
EGEAS – Electric Generation Expansion Analysis System
EGU – Electric Generating Unit
EPRI – Electric Power Research Institute
ESP – Electrostatic Precipitator
FD – Forced Draft
FGD – Flue Gas Desulfurization
FIP – Federal Implementation Plan
FTE – Full Time Equivalent
GHG – Green House Gas
gpm – gallons per minute
GWh – Gigawatt Hour
Hg – Mercury
hr - hour
ID – Induced Draft
IECCOST – Integrated Emissions Control Cost program
in. w.g. – inches of water gauge
IRP – Integrated Resources Plan
kW – Kilowatts
lb – pound
LSFO – Limestone with Forced Oxidation
MM- Million
MGE – Madison Gas and Electric Company
MMBtu – Million British Thermal Units
MW – Megawatts
NAAQS – National Ambient Air Quality Standards
NOx – Nitrogen Oxides
O&M – Operating and Maintenance
PM – Particulate Matter
$PM_{2.5}$ – Particulate Matter less than 2.5µm in diameter
PPA –Power Purchase Agreements
PSCW – Public Service Commission of Wisconsin
PRB – Powder River Basin
PVRR – Present Value Revenue Requirements
RPS – Renewable Portfolio Standard
SCR – Selective Catalytic Reduction
SDA – Spray Dryer Absorber
SIP – State Implementation Plan
SO_2 – Sulfur Dioxide
SO_3 – Sulfur Trioxide
TBtu – Trillion British Thermal Units
USEPA – United States Environmental Protection Agency
VOC – Volatile Organic Compound
WDNR – Wisconsin Department of Natural Resources
WPL – Wisconsin Power and Light Company
WPS – Wisconsin Public Service Corporation
wt% – weight % (percent by weight)
WWT – wastewater treatment
ZLD – Zero Liquid Discharge

BEFORE THE

PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Power and Light Company, Wisconsin Public Service Corporation, And Madison Gas and Electric Company for a Certificate of Authority to install Emissions Reduction Systems at the Columbia Energy Center Units 1 and 2	))))))	Docket No. 05-CE-138

APPLICATION

Wisconsin Power and Light Company (WPL), Wisconsin Public Service Corporation (WPS), and Madison Gas and Electric (MGE), referred to as "Applicants," apply, pursuant to Section 196.49 of the Wisconsin Statutes, Chapter PSC 112 of the Wisconsin Administrative Code and any other applicable statute or rule for a Certificate of Authority (CA) for an emissions reduction project at the Columbia Energy Center in Pardeeville, Wisconsin. This project is comprised of (1) the installation of dry SO_2 scrubbers, baghouses, and associated equipment; and (2) the modification and expansion of the existing activated carbon injection system for mercury control. This project is needed to meet current and future mercury and SO_2 reduction requirements of state and federal regulations.

WPL is a public utility organized and existing under the laws of the State of Wisconsin with its principle offices located at 4902 North Biltmore Lane, Madison, Wisconsin 53707.

WPS is a public utility organized and existing under the laws of the State of Wisconsin with its principle offices located at 700 North Adams Street, Green Bay, Wisconsin 54301.

MGE is a public utility organized and existing under the laws of the State of Wisconsin with its principle offices located at 133 South Blair Street, Madison, Wisconsin 53703.

Dated this 31 day of March, 2009.

Respectfully submitted,

By: ______________ ______________ ______________

WPL WPS MGE

EXECUTIVE SUMMARY

The co-owners of the Columbia Energy Center are applying for Commission approval of a Certificate of Authority (CA) to install certain emission controls at Columbia. This executive summary provides an overview of the full application.[1]

Wisconsin Power and Light Company (WPL), Wisconsin Public Service Corporation (WPS) and Madison Gas and Electric Company (MGE) own 46.2%, 31.8% and 22% of Columbia, respectively. Columbia consists of Unit 1 (512 nameplate MW) and Unit 2 (511 nameplate MW), with in-service dates of 1975 and 1978, respectively. The Applicants propose to install controls at Columbia that will reduce sulfur dioxide (SO_2) and mercury (Hg) emissions. Mercury controls are required by 2015 or else Columbia would need to be replaced prematurely. The Clean Air Interstate Rule (CAIR) requires industry wide SO_2 reduction starting in 2010. Existing and developing environmental regulations may require that unit-specific SO_2 controls be in service as early as the end of 2013. Specifically, the co-owners propose to install dry flue gas desulfurization (dry scrubber) equipment, an activated carbon injection (ACI) system, and baghouse, to reduce SO_2 and mercury emissions.

The proposed project has four primary benefits. First, the project will reduce emissions of SO_2 and mercury to support compliance with existing and anticipated regulations and will also capture fine particulate matter ($PM_{2.5}$) and reduce acid mist. Second, the project will save substantial money for ratepayers on a present value basis compared to premature replacement of Columbia as demonstrated by the Applicants' economic analyses. These savings range from \$0.7 to \$2.0 billion over a wide scope of possible futures. Third, the project will provide improved flexibility for meeting possible future regulations. Fourth, the project will provide a cost-effective bridge to a possible future that mandates greatly reduced carbon dioxide (CO_2) emissions. Premature replacement of Columbia would likely require construction of new gas-fired generators to replace the lost capacity.

The proposed project will reduce mercury emissions by 90% to comply with Wisconsin's mercury rule, NR 446. These reductions will be achieved by modifying the existing ACI system on Unit 2, expanding it to Unit 1, and installing a baghouse on each unit. In addition, SO_2 emissions will be reduced by 90% on each unit by installing dry scrubber systems to operate in conjunction with the baghouses. The reduced SO_2 emissions are needed to provide flexibility in complying with state and federal SO_2 emissions requirements, such as CAIR. The Applicants chose an ACI system with baghouse because it is a cost-effective way to achieve 90% mercury reduction. The Applicants chose a dry scrubber technology with baghouse because it is a cost-effective way to achieve 90% SO_2 reduction, and because the alternative wet scrubber technology would produce mercury contaminated wastewater – an unacceptable option at Columbia.

[1] The executive summary is deliberately non-technical and should be considered in light of the fuller technical detail in the full Application and appendices.

Tentatively, the Applicants plan to begin construction in the second quarter of 2010, with completion in 2013. Timely approval would allow schedule flexibility so that the Applicants could alter the actual construction timeline to adjust for changing environmental regulations. Schedule flexibility also would enable the Applicants to take advantage of market fluctuations for labor, material, and capital. Actual tie-in of the new equipment is expected to coincide with a regularly scheduled maintenance outage. The estimated cost is $627 million, exclusive of AFUDC, if any. The Applicants plan to finance the project as a traditional utility plant to be included in rate base.

The Applicants used the EGEAS (Electric Generation Expansion Analysis System) planning model to evaluate alternative environmental compliance plans. Four different compliance plan options were evaluated under ten alternative views of the future. In all, forty different scenarios (4 plans x 10 futures) were examined.

Plan 1 for Columbia compliance is the proposed project: a dry SO_2 scrubber on each unit and ACI system with baghouse. Plan 2 is the same as Plan 1 except for adding installation of a selective catalytic reduction (SCR) system to further reduce NOx emissions. Studying Plan 2 shows whether the proposed project remains a smart choice if subsequently further NOx reductions were to be required. Plan 3 considers the effects of delaying the mercury controls until 2015 and the SO_2 controls until 2018. Delay may yield savings, but may expose Applicants and ratepayers to significant risks, including the market risk associated with relying on SO_2 allowances. Plan 4 consists of not installing additional controls at Columbia. It assumes Columbia is replaced prematurely at the end of 2013. Under Plan 4, each company's EGEAS model chooses how it would replace the capacity lost by prematurely closing Columbia.

Each of the four plans was evaluated over a wide range of possible futures. Future 1 is based on the current regulatory landscape, with average or "normal" assumptions for gas prices, coal prices, and purchased power costs. SO_2 emissions have a monetized value, but CO_2 emissions do not have a monetized value. In Future 1, ratepayers save $1.5 billion by installing the proposed controls versus prematurely replacing Columbia.

Future 2 is the same as Future 1 except that CO_2 emissions are monetized using the values adopted by PSC staff in the Nelson Dewey 3 CPCN proceedings. In Future 2, ratepayers save $1.1 billion by installing controls versus prematurely replacing the plant.

Futures 3 and 4 are designed as "bookends" to cover a wide range of scenarios. Future 3 is a favorable future for continuing operations at Columbia: gas prices 30% higher than normal; coal prices 10% lower than normal; purchased power costs reflective of fuel costs; and, an assumption that the proposed project costs are 10% less than estimated. In Future 3, ratepayers save $1.9 billion by installing the controls. Future 4 is an unfavorable future for continuing operations at Columbia: gas prices 10% lower than normal; coal prices 30% higher than normal; purchased power costs reflective of fuel costs; and, an assumption that the project costs 20% more than estimated. Even under Future 4, a strongly anti-Columbia case, ratepayers save $0.7 billion by installing controls versus replacing the plant. Because the proposed project is favorable in both bookend scenarios, the Applicants chose not to study the numerous scenarios that would lie between the bookends.

Future 5 is a carbon constrained future. Not only are CO_2 emissions monetized, but also the renewable portfolio standard (RPS) is enhanced from 10% of retail sales in 2015 to 20% in 2020, and 25% in 2025. Fuel prices are allowed to adjust so as to reflect this carbon constrained future (coal prices reduced by 10% and natural gas prices increased by 30% to reflect a shift to lower carbon electric generation resources. In Future 5, ratepayers save $1.6 billion by installing controls versus replacing Columbia.

Futures 6 through 10 study several special cases. In Future 6, the Columbia units are assumed to be replaced with a "zero carbon emitting source priced at nuclear" in 2035 and 2038. That assumes the Columbia units will have a 60-year life. (They may well last longer.) In Future 6, ratepayers save $1.9 billion by installing the proposed controls at Columbia.

Future 7 envisions a requirement for even higher reductions in CO_2. Future 8 examines what happens if SO_2 allowance prices are high, which was simulated by increasing the assumed base SO_2 allowance value (prevailing market prices after CAIR vacatur in July 2008, $150/ton) by a factor of ten ($1,500/ton). This future examines the Applicants' risk exposure of relying on allowances versus installing controls. Futures 9 and 10 were suggested by PSC staff. The first assumes neither WPL nor WPS extend their purchased power agreements (PPAs) for Kewaunee Nuclear Power Plant. Future 10 assumes WPS does not enter a PPA with Manitoba Hydro. Under Futures 7, 8, 9 and 10, ratepayer savings are $2.0 billion, $1.6 billion, $[redacted] billion and $[redacted] billion, respectively, from installing controls versus replacing Columbia.

In summary, the EGEAS analyses show that the proposed project saves significant money for ratepayers over a wide range of futures. Moreover, the project provides flexibility. It remains economical even if further NOx controls are required in the future, and even if CO_2 is monetized in a highly carbon constrained world. Finally, the project provides a cost-effective bridge to a carbon constrained future. For these reasons, and further reasons as detailed in the full application, the Applicants seek approval to install the proposed environmental controls at Columbia.

INTRODUCTION

With this Certificate of Authority Application, Wisconsin Power and Light Company (WPL), Wisconsin Public Service Corporation (WPS), and Madison Gas and Electric Company (MGE), collectively referred to as Applicants, request authorization to install mercury (Hg) and sulfur dioxide (SO_2) emission control systems on Units 1 and 2 at the Columbia Energy Center (Columbia). The Applicants jointly own these Units, with WPL holding a 46.2% share, WPS holding a 31.8% share, and MGE owning the remaining 22%. WPL operates the Units. Units 1 and 2 each consist of a tangentially-fired boiler and steam turbine generator with nameplate generating capacities of 512 and 511 megawatts (MW), respectively. Each Unit is equipped with an electrostatic precipitator (ESP) for particulate emissions control. In addition, an activated carbon injection (ACI) system was recently installed on Unit 2 for mercury control.[2]

The proposed emissions reduction project will reduce mercury emissions by 90% to comply with Wisconsin's mercury rule, Chapter NR 446 of the Wisconsin Administrative Code (NR 446). Mercury emissions will be reduced by modifying the Unit 2 ACI system and expanding it to Unit 1. In addition, SO_2 emissions will be reduced by 90% on each Unit through the installation of dry flue gas desulfurization (dry FGD) system, comprised of spray dryer absorbers (SDAs) and a baghouse on each Unit. The baghouses will be used for both dry FGD and ACI technologies, and will play an important role in capturing mercury and SO_2 emissions. The SO_2 removal achieved by the dry FGD systems is necessary to support compliance with state and federal emission reduction requirements, notably those associated with the federal Clean Air Visibility Rule (CAVR) and Clean Air Interstate Rule (CAIR) programs. Finally, the proposed systems will have the co-benefit of reducing emissions of fine particulate matter ($PM_{2.5}$), particularly through the reduction of SO_2, a pre-cursor for $PM_{2.5}$, aiding in the maintenance of $PM_{2.5}$ attainment in Columbia County and surrounding areas.

Timely approval of the project will allow schedule flexibility so that the Applicants can alter the actual construction timeline to adjust for changing environmental regulations as well as take advantage of market fluctuations in labor, materials, and capital.

The Applicants have determined that a dry FGD system, specifically SDA and baghouse, coupled with an ACI system is the most practical and economic method of controlling mercury and SO_2 emissions from Columbia Units 1 and 2 for the following reasons:

- These technologies will result in reduction of mercury and SO_2 emissions that are expected to meet or exceed regulatory requirements under NR 446, CAIR, CAVR, and BART, and provide optionality in meeting anticipated future regulations.

[2] The Unit 2 ACI project was installed in 2008 for carbon injection upstream of the existing ESP. The project had a capital cost below the Commission's threshold for a CA filing. (See Wis. Admin. Code § PSC 112.05(3)). A notification letter to the PSCW regarding this project is included in Appendix G.

- The dry FGD technology has been commercially proven for applications comparable to Columbia Units 1 and 2.
- The dry FGD technology results in no additional wastewater discharge, particularly mercury-contaminated water discharge.
- The selected technologies provide co-benefits including capturing fine particulate matter ($PM_{2.5}$) and acid mist.
- Investment in mercury and SO_2 emissions controls at Columbia and continued operation of the plant will provide a significant economic benefit to the ratepayer when compared to premature replacement of the facility.

The proposed ACI and dry FGD systems are expected to remove over 11,000 pounds of mercury and over 500,000 tons of SO_2 from Columbia Units 1 and 2 current emissions over a 25 year period. The proposed system will consume an auxiliary load of 16 MW of the 1,023 MW nameplate generation capacity of the Units.

An economic analysis of the proposed project was completed using the Electric Generation Expansion Analysis System (EGEAS) model (See Appendix C). The analysis demonstrates that premature replacement of the Units would increase ratepayer life cycle present value revenue requirements (PVRR) by $0.7 to $2.0 billion compared to investing the estimated $627 million in the emissions control project and continuing operation of the plant.

The information provided in this Application, including the site layout and the proposed construction approach is based on preliminary design information, and is subject to revision with further detailed design and selection of equipment vendors.

1.0 Project Description

The Columbia Energy Center (Columbia) is located in Pardeeville, Wisconsin (See Figure 1). Columbia Units 1 and 2 began operation in 1975 and 1978 and have nameplate generation capacities of 512 and 511 MW, respectively. The Units are jointly owned by Wisconsin Power and Light Company (WPL), Wisconsin Public Service Corporation (WPS), and Madison Gas and Electric (MGE), who own respective shares of 46.2%, 31.8%, and 22%. The Units are operated by WPL.

The Units burn sub-bituminous Powder River Basin (PRB) coal from various mines. The preliminary design of the dry flue gas desulfurization (FGD) and activated carbon injection (ACI) systems is based on a design coal[3] that represents the full range of PRB fuel. The Units use electrostatic precipitators (ESPs) to collect particulate matter (PM), namely flyash. Unit 1 operates with a hot-side ESP and Unit 2 operates a cold-side ESP with sulfur trioxide (SO_3) injection. Both Units operate low-NOx burners and overfire air combustion technology to reduce emissions of nitrogen oxides (NOx). An ACI system was installed on Unit 2 upstream of the existing ESP in 2008 for mercury removal.

The proposed emissions reduction project includes the following:

- Expansion of the existing ACI system to Unit 1 to provide carbon injection upstream of the new baghouse and SDA. The baghouses will capture spray dryer solids, residual flyash, and activated carbon, including bound mercury.
- Installation of dry FGD systems on both Units. Specifically, two spray dryer absorber (SDA) vessels and a downstream baghouse will be installed on each unit (four SDA vessels and two baghouses in total) for SO_2 emissions reduction.
- Modification of the recently installed ACI system at Unit 2 to relocate the carbon injection point downstream of the existing ESP. Moving this injection point allows the plant to maintain beneficial reuse of the flyash.

The emissions reduction project includes the following auxiliary equipment:

- Lime storage, lime slurry preparation equipment (common to Units 1 and 2 dry FGD)
- Solids recycle equipment if applicable to specific vendor design
- Activated carbon storage and handling (modification to the Unit 2 ACI system)
- Induced draft booster fans
- Waste material handling equipment
- Associated ductwork
- A new controls building and new electrical equipment.

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[3] *Design coal* is defined in this application as coal that will be used for design and sizing of the dry FGD and ACI systems as well as determining costs for equipment. This coal may not be the coal that was used in the original design of the Columbia Energy Center or the coal currently used at the site.

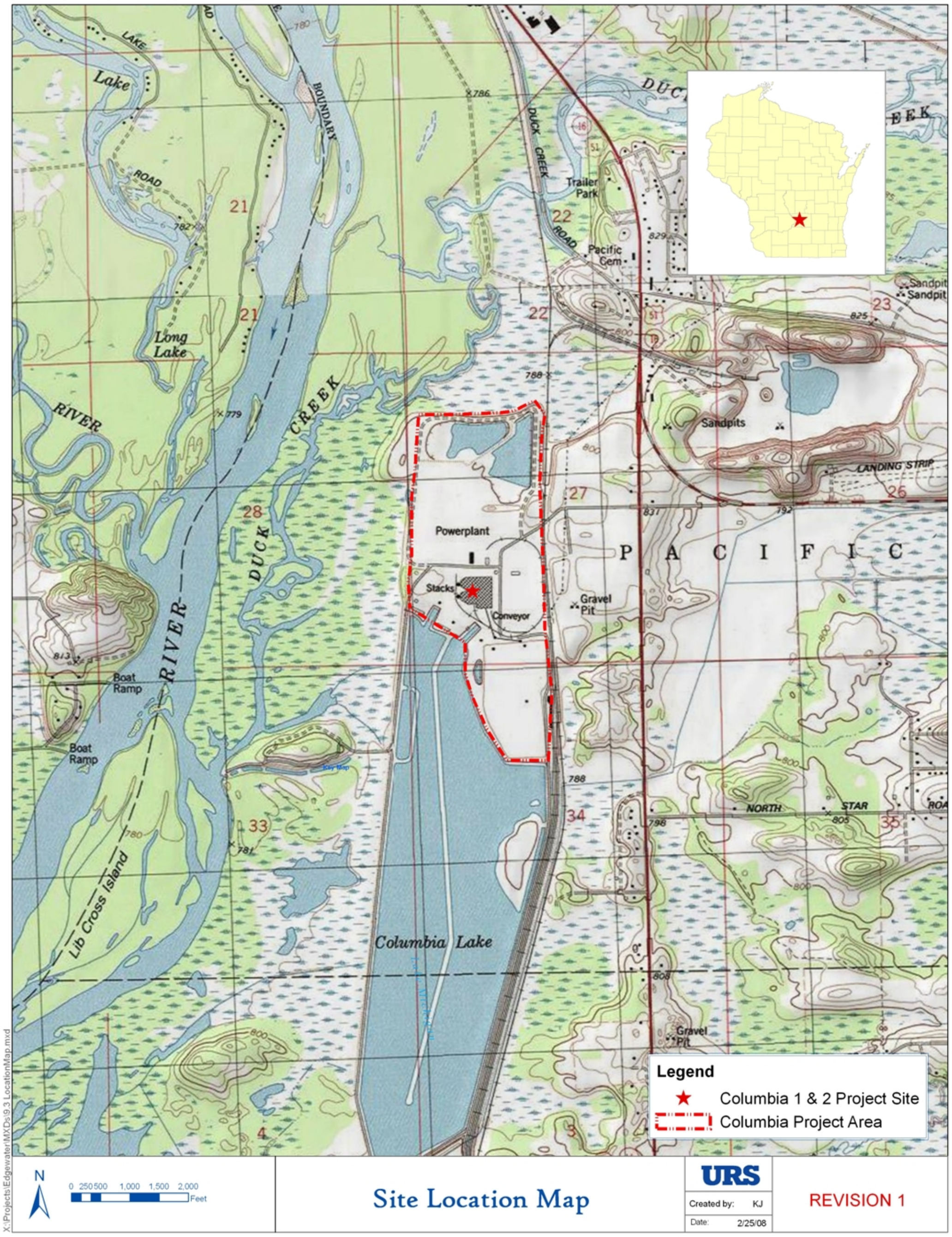

Figure 1. Columbia Units 1 and 2 Project Location Map

The dry FGD system is designed to reduce SO_2 emissions from Units 1 and 2 to support compliance with the Clean Air Visibility Rule (CAVR) and Clean Air Interstate Rule (CAIR) program requirements, and the ACI system and baghouse combination are expected to reduce mercury emissions by 90% to achieve compliance with NR 446. A co-benefit of the installed system is its ability to reduce fine particulate ($PM_{2.5}$) emissions, primarily through the reduction of SO_2, which is a precursor to $PM_{2.5}$.

The site arrangement in Figure 2 shows a plot plan of the proposed dry FGD and ACI systems relative to the existing Units. The ACI equipment installed in 2008 consists of a storage silo, blower, injection grid and connective piping. These items are shown collectively as Item 18 on this plot plan. A larger version of the drawing is provided in Appendix A.

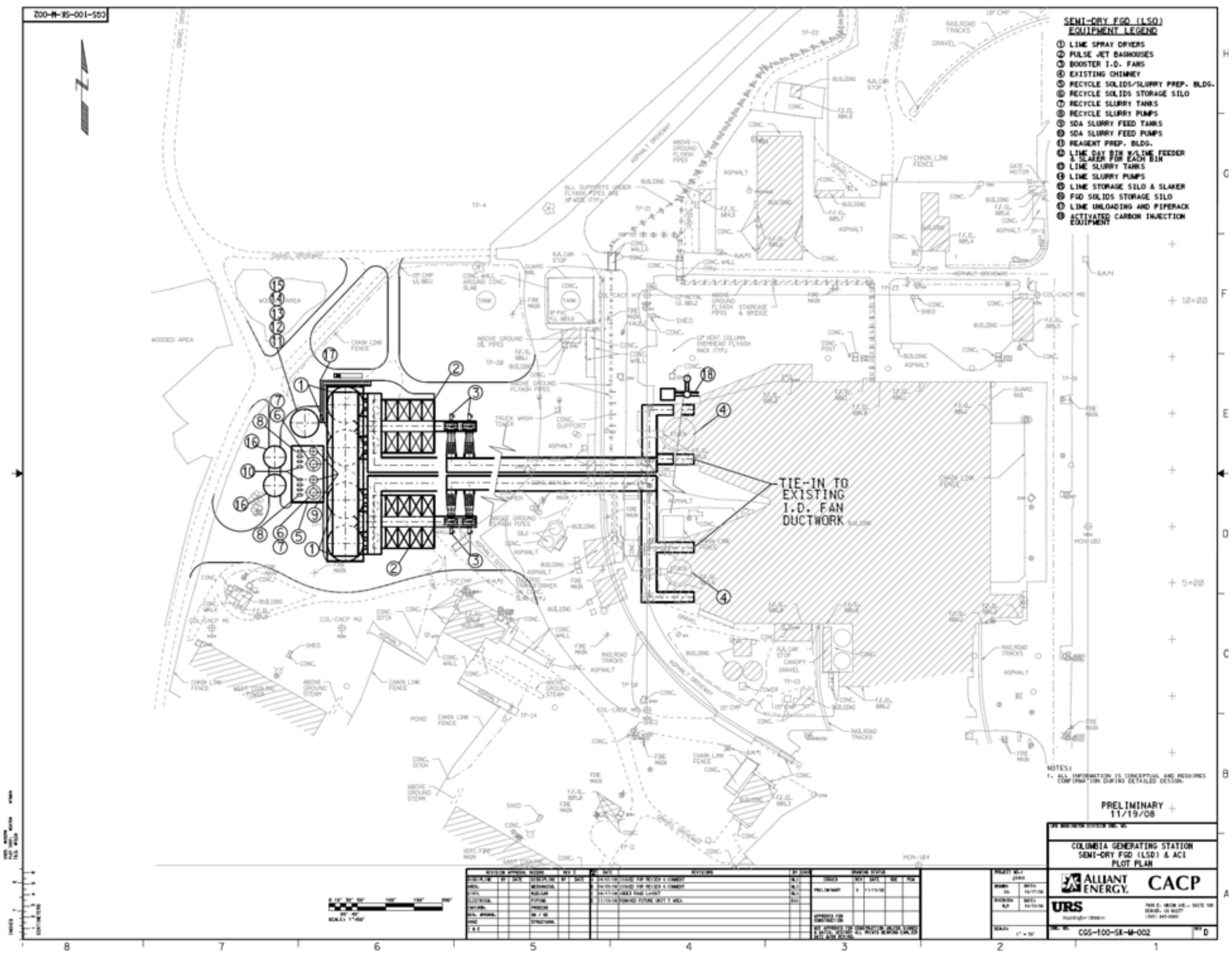

Figure 2. Site Layout – Proposed Columbia Units 1 and 2 Dry FGD and ACI Systems

The SDA vessels and baghouses will be located west of existing plant operations, in an open area of the plant site. New ductwork will tie-in to existing ductwork upstream of the existing stacks and will run to the inlet of the SDA vessels. Lime receiving and preparation equipment will be located west of the SDA vessels to allow convenient transfer to the SDA lime supply pumps. New booster fans and ductwork located downstream and east of the new baghouses will transfer the flue gas to tie-in at the existing stacks.

Activated carbon will be conveyed to the new sections of ductwork for injection downstream of the ESPs and upstream of the SDAs and baghouses. The existing ACI system was designed for Unit 2. Modifications to the existing system may include new blowers, new pipe to convey the carbon to the injection points upstream of the baghouses, and possibly additional storage capacity.

Most of the construction activities will occur in an uncongested area on the west side of the plant and will have minimal impact on existing operations. Outages will be required to tie-in the SDAs and baghouses. Applicants plan to minimize plant down-time by taking advantage of planned maintenance outages to tie-in the new equipment. Laydown space is available directly north of the construction area with available road access to the construction area already in place. Minimal demolition work will be required for the project (See Section 5).

1.1 Technology Objectives

The dry FGD and ACI systems for Columbia Units 1 and 2 will be designed to meet the following objectives:

- Reduce mercury emissions by 90% in accordance with NR 446.
- Reduce SO_2 emissions to support CAVR and CAIR program compliance.
- Reduce both SO_2 and mercury emissions in a cost-effective manner.
- Minimize waste generated, especially mercury contaminated wastewater.
- Allow fuel and operational flexibility.
- Minimize the outage time necessary to tie-in new equipment, as well as any other disruptions to operations during the construction period.
- Maintain the reliability, operability, and performance of the Units.
- Maximize co-benefit emissions reductions, including $PM_{2.5}$, and allow optionality for compliance with future regulations.

1.2 Selected Technology

High-level overviews of the dry FGD and ACI technologies are provided in this section. The dry FGD and ACI systems were chosen for application at Columbia Units 1 and 2 because they provide a cost-effective and efficient means to meet current and anticipated regulatory requirements for mercury and SO_2 emissions. Evaluations of the selected and alternative technologies, as applied to Columbia Units 1 and 2, are summarized in Section 6 and Appendix B. Generic descriptions of these technologies are presented in Appendices E and F.

1.2.1 Activated Carbon Injection (ACI)

The injection of activated carbon into flue gas is considered the most mature technology available for mercury removal from coal combustion emissions. In the ACI process, carbon is injected into the flue gas upstream of a baghouse or ESP. Mercury in the flue gas adsorbs to the surface of the activated carbon. The activated carbon containing bound mercury is collected in the downstream particulate control device.

Mercury in the flue gas may be in the form of elemental mercury (Hg^0) or oxidized mercury (Hg^{2+}). Elemental mercury is more difficult to capture. Columbia Units 1 and 2 burn PRB coal, the flue gas of which is dominated by elemental mercury. ACI is one of the few mercury control technologies that has demonstrated high removal efficiency of the total mercury from the flue gas, including both elemental and oxidized mercury.

Mercury removal efficiency from an ACI system is affected by the type of downstream particulate control device. In general, in order to achieve a mercury removal rate of 90%, a baghouse must be used for collection downstream of carbon injection. Commercial testing of carbon injection upstream of a typical ESP has shown removal efficiencies of 50 – 80%. Furthermore, hot-side ESPs achieve lower removal efficiencies than cold-side ESPs due to the reduced adsorption capacity of activated carbon at elevated temperatures. The current particulate control devices at Columbia are a cold-side ESP on Unit 2 and a hot-side ESP on Unit 1. In addition, most flyash collected with activated carbon used for mercury control is not marketable for beneficial reuse. Therefore, it is beneficial to install a baghouse downstream of an existing ESP to achieve greater mercury removal and to preserve beneficial reuse of the flyash.

At the Columbia Energy Center, the Unit 2 ACI system was installed upstream of the cold-side ESP. A downstream baghouse is required to meet the 2015 mercury emissions removal requirement of 90%. The proposed project will utilize the baghouses installed downstream of the SDAs to collect dry FGD solids and activated carbon containing bound mercury from both Units 1 and 2. Solids collected in the baghouse will be appropriately landfilled.

1.2.2 Dry Flue Gas Desulfurization (FGD)

The technology proposed for SO_2 emissions reduction at Columbia Units 1 and 2 is a combination of spray dryer absorber (SDA) and baghouse. With the SDA technology, the flue gas exiting the air heater or existing particulate control device enters a spray dryer vessel. In the vessel, atomized slurry of lime and recycled solids is injected into the flue gas stream. Sulfur oxides (SO_2 and SO_3) in the flue gas react with lime reagent to form calcium salts ($CaSO_3$, $CaSO_4$). The major reactions in the absorber vessel are as follows:

Lime Hydration:	$CaO + H_2O \rightarrow Ca(OH)_2$
SOx Reactions:	$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet H_2O + \frac{1}{2} H_2O$
	$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$
Sulfite Oxidation:	$Ca(OH)_2 + SO_2 + H_2O + \frac{1}{2} O_2 \rightarrow CaSO_4 \bullet 2H_2O$

Water in the lime slurry vaporizes in the vessel, lowering the temperature and raising the moisture content of the scrubbed gas. A baghouse, installed downstream of the SDA, removes dry solids and flyash that do not fall out in the vessel. A portion of the reaction products and remaining flyash solids from the baghouse may be recycled to the lime slurry feed system depending on the vendor-specific design. The remaining byproduct solids from the baghouse are sent to a landfill for disposal.

In summary, the following attributes make SDA, baghouse, and ACI attractive technologies for reduction of mercury and SO_2 emissions from Columbia Units 1 and 2:

- Mercury captured and disposed of as a solid waste.
- No mercury-contaminated wastewater discharge.
- Co-benefit emissions capture, including reduction of $PM_{2.5}$, acid mist (SO_3/H_2SO_4), and lead.
- No additional major equipment for the ACI system when coupled with the baghouses installed for the dry FGD system.
- High mercury removal achieved with ACI and a baghouse.
- Continuation of beneficial reuse of the flyash.
- Ability to maintain the service of the existing chimneys.

1.3 Construction Approach

The following is a high-level overview of the construction approach for the project, which focuses on minimizing the required outage of the Units and the impact of construction on facility operations. The Applicants plan to minimize plant down-time by coordinating the tie-in of equipment with regularly scheduled maintenance outage time.

<u>Civil</u>
Structures, components, and foundations will be designed so that their strength equals or exceeds the effects of factored load combinations. A geotechnical report has been used to define foundation requirements. Buildings will enclose and protect the equipment. Foundations for the primary equipment will be the first structures constructed upon start of construction.

<u>Demolition</u>
A majority of the new equipment, including the spray dryers, baghouses, induced draft (ID) booster fans, and lime handling equipment, will be located in an open area. Accordingly, the project will not require significant demolition or relocation of equipment or facilities. Area preparation will require ground leveling and removal of the solids pile extraction equipment. This work will need to be completed before the foundations for the major equipment are constructed. Additionally, the following equipment will be removed: two concrete flyash silos, a loadout silo, a fuel oil tank, and a short length of pipe rack. (See Section 5 and Appendix A for further detail on demolition plans.)

<u>Activated Carbon Injection (ACI) System</u>
An ACI system consists of activated carbon unloading and storage silos, skid-mounted activated carbon feeder equipment, piping, and a distribution manifold across the

ductwork. The current Unit 2 ACI system, including the storage silo and feeder equipment, will be utilized for this project. With installation of the baghouses on Units 1 and 2, the ACI system will be expanded to include carbon injection upstream of the SDA and baghouse on Unit 1. Also, the Unit 2 injection point will be moved to inject carbon into new ductwork downstream of the ESP, prior to the dry FGD system. These modifications may require additional activated carbon storage and feeder equipment and new lines to convey the activated carbon to the new injection points.

Spray Dryer Absorber (SDA) and Baghouse
The absorber vessels and baghouse equipment will be fabricated off-site and shipped in large pieces to the project site. Fabrication philosophy will be finalized upon selection of the equipment vendors, and will emphasize minimizing on-site fabrication.

Ductwork
Rectangular steel plate ductwork, including duct plate, stiffeners, and ductwork support structure will be shipped to the site for installation. Some ductwork may be shop fabricated prior to shipment to minimize on-site fabrication.

Mechanical Equipment
New mechanical equipment includes new ID booster fans and motors, lime unloading and processing equipment, lime slurry feed and recycle pumps, solids handling equipment, and blowers. Lime receiving, storage, and handling equipment will be common to the dry FGD systems on both Units. The equipment details will be finalized in the detailed engineering phase, after equipment vendors have been selected.

Electrical
The electrical power source for the new equipment will be fed from the plant substation to two new fully redundant auxiliary power transformers. Major components of the electrical system include feeder cables from existing switchgear, auxiliary transformers, motor control centers, substations, and system grounding.

Instrumentation and Controls
New instrumentation and controls are required for the dry FGD and ACI system operations. The additional instrumentation and controls will be integrated into the plant's existing distributed control system (DCS). The primary control functions will be automated process control, system monitoring, and operational alarms. New controllers and operator and engineering workstations will be provided with the new instrumentation and controls equipment.

1.4 Constructability Summary

Based on site reviews and assessments done by engineering consultants, dry FGD and ACI systems are feasible for installation and operation on Columbia Units 1 and 2. Retrofit work should be completed with minimal impact to existing operations due to the open space available for construction and installation of new equipment. The following will be completed prior to finalizing the engineering plan and construction approach:

- Selection of dry FGD equipment vendor
- Layout of vendor-specific equipment
- Boiler implosion and transient analysis

The site layout and construction approach will be finalized during detailed engineering.

1.5 Milestone Schedule

Wisconsin's mercury rule, NR 446, mandates 90% reduction in mercury emissions by 2015. Compliance with SO_2 emission reduction requirements is less definitive given the current state of environmental regulations, but the Applicants expect that SO_2 control systems will need to be operational in the 2013 to 2018 timeframe. Timely approval of this project will provide the Applicants schedule flexibility to adjust to changing environmental regulations and take advantage of market fluctuations in labor, materials, and capital.

Milestone	**Date**
Submit CA Application to PSCW	March 2009
Award detailed engineering and procurement contract[a] (limited notice to proceed)	July 2009
Receive CA (expected)	1st Quarter 2010
Receive environmental permits (expected)	1st Quarter 2010

a. Includes balance of plant engineering and preparation of the specifications for the emissions control equipment.

The table below presents a preliminary milestone schedule for construction of the Columbia Units 1 and 2 emissions reduction project. This schedule serves as the basis for the EGEAS analysis. The schedule is based on commercial operation of the mercury and SO_2 systems in 2013, the earliest possible compliance date. To assist in understanding the impact of delaying the construction schedule, the Applicants modeled a completion date of 2015 for mercury control and a completion date of 2018 for SO_2 control. The EGEAS analyses are discussed further in Section 3.3.2 and Appendix C. The project schedule will be refined after the engineering, procurement, and construction contracts have been signed, detailed engineering begins, and after receipt of regulatory approval.

Milestone	**Date**
Begin Construction	2nd Quarter 2010
SDA and baghouse system check out	3rd Quarter 2012
Columbia Unit 1 tie-in outage	4th Quarter 2012
Columbia Unit 2 tie-in outage	1st Quarter 2013
Project completion	June 2013

2.0 Cost and Financing Estimates

An independent engineering consultant developed capital and operating and maintenance (O&M) cost estimates for the emissions reduction project at Columbia. The total project estimate presented in this section includes the following major items:

- Civil, Structural, and Architectural Items – foundations, support and structural steel, and flue gas ductwork
- Mechanical and Process Equipment – dry FGD and baghouse equipment, ACI silos and air blowers, lime reagent and solids handling equipment, process piping, fire protection, spare parts, and balance of plant mechanical systems
- Electrical Systems – auxiliary power distribution, lighting, grounding, heat tracing, and the construction power system
- Instrumentation and Controls – distributed control system (DCS) integration into existing system and local instrumentation and controls of process equipment
- Balance of Plant – steel, concrete, demolition and relocation and site preparation work
- Fees – engineering, construction management, and start-up services, including commissioning and performance testing
- Owners' Costs – project personnel, training, licensing and permitting support, insurance, and initial reagent inventory

Costs presented in this Application represent the engineering consultant's estimate, prepared in April 2008, based on budgetary quotes received from dry FGD system vendors. The Applicants' internal costs, the cost of spare equipment, contingency, and insurance expenditures are also included in the cost estimate. Based on the preliminary engineering and estimates, the total project cost has an expected accuracy of +20%/-10%. As detailed engineering work progresses, project cost estimates will be refined and the estimate accuracy will improve.

2.1 Estimated Capital Cost and Cash Flow

Estimated costs for the Columbia emissions reduction project are provided in Table 1 and are based upon the schedule presented in Section 1.5. The costs presented are inclusive of the Applicants' internal costs. The costs do not include Allowance for Funds Used During Construction (AFUDC).[4]

[4] AFUDC is the process of including as a part of the total project the applicable carrying costs on Construction Work In Progress (CWIP) expenditures. If such CWIP balances are included in net investment rate base in a rate proceeding, then AFUDC would not be included or computed on such amounts. WPL, WPS, and MGE anticipate that they will propose different rate treatments of the costs of this project. EGEAS runs assume 100% CWIP to be included in the rate base for all three applicants.

Table 1. Columbia Units 1 and 2 Emissions Reduction Project Estimated Capital Cost

Description	Cost ($)
SDAs and Lime Handling	$58,200,000
ACI Systems, Baghouses and ID Fans	$82,600,000
Solids Handling Equipment	$7,200,000
Ductwork Modifications	$50,100,000
Miscellaneous Equipment / Balance of Plant	$77,100,000
General Facilities	$10,000,000
Indirect Costs	$6,600,000
Craft Labor / Installation	$49,200,000
Engineering / Construction Management / Start-Up Services	$74,600,000
Sub-Total	**$415,500,000**
Contingency	$80,200,000
Escalation	$25,700,000
Total Plant Cost (TPC)	**$521,300,000**
Prime Contractor's Markup[a]	$55,500,000
Owners' Costs[b]	$50,000,000
Total Project Cost[c]	**$627,000,000**

a. Prime contractor's markup includes general and administrative costs and fees incurred by the engineering, procurement, and construction contractor.

b. Owners' costs include costs associated with the Applicants' management of the project, permitting, hiring and training operating staff, and overhead during construction.

c. The total project cost in Table 1 includes $6.7 million for the Unit 2 ACI system. Costs that will actually be incurred as a part of this project are for ACI system modifications, including expansion to Unit 1 and relocation of the carbon injection point on Unit 2. In this Application, the Applicants seek funds associated only with these modifications.

Cash flow estimates for the project schedule in Section 1.5 are presented in Table 2. These costs include escalation and contingency, and as stated above, do not include AFUDC.

Table 2. Columbia Units 1 and 2 Emissions Reduction Project Annual Cash Flow

Year	WPL Annual Cash Flow ($)	WPS Annual Cash Flow ($)	MGE Annual Cash Flow ($)	Total Annual Cash Flow ($)[a]	Annual % of Total Cost
2008	$3,880,000	$2,670,000	$1,850,000	$8,400,000	1.4%
2009	$17,380,000	$11,960,000	$8,280,000	$37,620,000	6.0%
2010	$55,040,000	$37,880,000	$26,210,000	$119,130,000	19.0%
2011	$86,900,000	$59,820,000	$41,380,000	$188,100,000	30.0%
2012	$95,590,000	$65,800,000	$45,520,000	$206,910,000	33.0%
2013	$29,910,000	$20,590,000	$14,240,000	$64,740,000	10.3%
2014	$970,000	$670,000	$460,000	$2,100,000	0.3%
Total Cost	$289,670,000	$199,390,000	137,940,000	**$627,000,000**	**100.0%**

a. Costs are presented in year-of-occurrence dollars.

Actual project costs and cash flow will vary depending upon project approval timing, actual project schedule, and market conditions.

2.2 Financing Mechanism

The Columbia emissions reduction project is proposed as a rate-based project financed using the traditional utility capital structure. As requested by the individual Applicants, AFUDC will be included as part of the construction costs. Upon completion of the project, the capital costs, including AFUDC, will be transferred to the appropriate electric utility plant accounts and recovered through traditional ratemaking treatment.

For their portion of the project, Wisconsin Public Service Corporation (WPS) requests the authority to accrue AFUDC on 100% of the CWIP through December 31, 2010. Effective January 1, 2011, WPS requests the authority to accrue AFUDC on 50% of CWIP and to recover a current return on the remaining 50% of CWIP. The estimated WPS AFUDC cost for the project is $18,150,000.

Rate treatment for Wisconsin Power and Light's (WPL) and Madison Gas and Electric's (MGE) portion of AFUDC will be proposed at a later date.

3.0 Project Need and Analysis of Alternatives

3.1 Background

This section provides an overview of the planning analysis used in determining the need for the proposed Columbia emissions reduction project. The decision to install emissions controls at Columbia Units 1 and 2 is a response to the promulgation of increasingly stringent air quality regulations. The Applicants deem the project necessary for their respective operational strategies and long-term emission compliance programs. The following sections describe the compliance planning process, and the need and rationale for installation of the control systems on Columbia Units 1 and 2. This planning process was undertaken by WPL. The co-owners, WPS and MGE, have both reviewed the proposed project and support going forward with this Application.

3.2 WPL Emissions Compliance Planning Process

3.2.1 Compliance Strategy

Air emissions are managed on a system basis through a strategic planning process and multi-emission strategy that considers both increasingly stringent environmental requirements and changing demand on electric generating units (EGUs). This planning process is highly dynamic and continually evolving. Work associated with the planning process encompasses strategy development, long-term strategic planning, and shorter-term tactical implementation. The basic components include:

1. Review and update Integrated Resource Plan (IRP).
2. Evaluate engineering aspects of emissions control technical and cost data, including plant operational constraints.
3. Develop scenarios of future air emission reduction requirements by identifying known, pending, and proposed new regulations.
4. Select an air emission plan based on regulatory compliance and optionality, net present value of total cost to rate payers, feasibility of implementation, and technology performance.
5. Implement near-term tactical responses for air emission plan as components of the longer-term strategy.

These components of the planning process are further described in Sections 3.2.2 – 3.2.6.

3.2.2 Update Integrated Resources Plan (IRP)

The emission planning process includes projections of electricity demand on the EGUs based on the IRP. The IRP shows how the utility intends to balance the anticipated system energy demand with energy supply. System energy demand is estimated using a year-by-year forecast that includes customer demand, energy required at the time of maximum consumption, and the total amount of energy consumed. The forecast of energy demand includes residential, commercial, and industrial customers. The forecast incorporates new customers based upon historical trends, and analyzes changes associated with using energy more efficiently. Through the IRP, the utility determines the most feasible and economic approach to varying electricity demand and regulatory requirements.

The forecast of energy demand developed through the IRP is matched against existing energy supply. The computer model EGEAS (Electric Generation Expansion Analysis) matches existing and feasible combinations of future energy supply alternatives with the forecasted energy needs. EGEAS is a modular production costing and energy supply expansion software package developed under the sponsorship of the Electric Power Research Institute (EPRI).

The EGEAS model focuses on choosing economically optimal energy supply for various scenarios that may manifest during the planning period, typically twenty years or more. Combinations of conditions that are uncertain during the planning period comprise the various scenarios. These conditions include energy demand, fuel prices, energy supply capital costs, purchased power costs, and emissions reduction values. EGEAS tests feasible combinations of future energy supply alternatives to determine economically optimal combinations for each scenario analyzed. Each energy supply alternative is modeled using expected energy need and production characteristics, as well as operating and capital costs, on a monthly basis. A combination of energy supply alternatives is defined to be economically optimal if it minimizes the cumulative present worth of the revenue requirements during the planning period and maintains a defined level of energy supply reliability.

The IRP process must also consider financial, operational, and regulatory risks which the EGEAS model cannot explicitly incorporate. These risks are considered as part of the broader IRP process. After carefully considering the scenarios analyzed using the EGEAS model and their associated financial, operational, and regulatory risks, an IRP reference base case is constructed that uses the projected future generating unit output for postulating future air emissions.

3.2.3 Evaluate Engineering Aspects of Emission Control Systems

Air pollution control systems are evaluated for incorporation into the emission compliance plan, factoring in current information on technology performance, cost, and operational constraints.

<u>Commercially Available Control Technologies</u>

The current status of emission control technology performance is monitored and evaluated through trade organizations, emission control equipment suppliers, and engineering design firms that support the installation of emission control equipment. This information assists in determining appropriate emission control options to consider for long-term emissions planning. Once long-term strategic emissions plans are approved, technical staff proceeds with preliminary engineering necessary to make the final selection of plant and unit-specific emission controls.

Physical and Operational Constraints

Each power plant site and EGU is unique in its configuration. This presents specific engineering and design challenges that must be considered in the emission planning process, including fuel use and fuel use capability, current emission control equipment performance, physical space available for new emission controls, necessary equipment upgrades to support emission controls, required maintenance, and the potential need to shut down units for prolonged periods. Each stakeholder must coordinate its power plant outages with those of other regional power plants and the electric transmission system operator to confirm adequate power is available during outage periods. The engineering services group defines possible timing of control installation, including planned outages and other power plant maintenance activities, to ensure the continuation of reliable and cost-effective utility operations during emission control equipment installation.

3.2.4 Planning for Air Emissions Regulatory Requirements

Multi-emission planning requires the evaluation of current and potential future air emission regulations and associated impacts to the emission compliance process. Understanding the regulatory framework governing current, pending, and future air emission requirements is inherent to the development of a flexible multi-emission strategy that can adjust to changes in regulatory requirements. The following discussion summarizes the status of current state and federal air regulations, policy developments, and their applicability to the Columbia Energy Center.

Wisconsin Mercury Rule

In December 2008, the Wisconsin Department of Natural Resources (WDNR) promulgated revisions to NR 446, the Wisconsin state mercury rule. NR 446 requires utilities to reduce mercury emissions by 40% by 2010. Further, coal-fired EGUs greater than 150 MW must reduce mercury emissions by 90% or limit outlet concentrations to 0.0080 pounds per GWh of energy generated, by 2015. The rule does not require a specific method or technology for the reductions, and therefore allows affected utilities to select control options that are both cost-effective and suited to the utility's particular needs. A utility may achieve compliance with the 2015 requirements either on a unit-by-unit basis where each EGU meets the mercury emission limit, or by unit averaging.

NR 446 includes an option to phase in mercury reductions if the utility also installs NOx and SO_2 controls. The phase-in approach allows mercury reductions of 70% by 2015, 80% by 2018, and 90% by 2021, with the stipulation that NOx and SO_2 emission rates will be less than or equal to 0.07 lb/MMBtu and 0.10 lb/MMBtu, respectively, by 2015.

The Federal Clean Air Act

The Clean Air Act (CAA) directs the United States Environmental Protection Agency (USEPA) to establish regulatory requirements for various air pollutants to ensure that all citizens are afforded the same health and environmental protections. The CAA recognizes that individual states are often better positioned to impose state-specific air emission requirements based on local air quality issues and affected industrial sectors. Through the WDNR, Wisconsin implements many CAA requirements within its borders, including the development and implementation of a USEPA-approved state implementation plan (SIP), a collection of state-specific regulations designed to ensure that air quality objectives are met.

In the event that a SIP is not approved, either in whole or in part, the USEPA may assume enforcement of the applicable CAA provisions in the affected state by issuing a federal implementation plan (FIP). If imposed, the FIP governs applicable regulatory requirements for the state until a SIP is approved.

Under the CAA, the USEPA is required to establish National Ambient Air Quality Standards (NAAQS) protective of public health and the environment. At present, NAAQS are established for the following criteria pollutants:

- Nitrogen oxides (NOx)
- Sulfur dioxide (SO_2)
- Particulate matter (PM_{10} and $PM_{2.5}$)
- Ozone
- Carbon monoxide (CO)
- Lead

Combustion of fossil fuels to produce electricity results in direct air emissions of the criteria pollutants NOx, SO_2, CO, and PM. Additionally, emissions of NOx and SO_2 react in the atmosphere to form fine aerosols, classified as $PM_{2.5}$. Ozone is not directly emitted by power plants, but is formed via photochemical reaction in the atmosphere of NOx with volatile organic compounds (VOCs).

The SIP specifies regulations that each state will utilize to attain or maintain NAAQS and related CAA requirements. Areas which comply with an applicable NAAQS are considered to be in *attainment* on a pollutant-specific basis. Locations which do not comply with an applicable NAAQS are referred to as *non-attainment areas* for a specific pollutant. Non-attainment areas are subject to more stringent air emission requirements designed to reduce ambient air concentrations of the criteria pollutant. The Columbia Energy Center is located in an area currently designated by the USEPA as being in attainment for all air pollutants except $PM_{2.5}$. On December 22, 2008, the USEPA designated part of Columbia County as a non-attainment area for $PM_{2.5}$. In February

2009, WDNR submitted data to the USEPA demonstrating attainment. The USEPA final designation is pending.

Clean Air Interstate Rule (CAIR)

In 2005, the USEPA issued the Clean Air Interstate Rule (CAIR) which requires reductions of SO_2 and NOx emissions from existing and new EGUs with capacities exceeding 25 MW. This rule caps SO_2 and NOx emissions in 28 states in the eastern U.S., including Wisconsin. When fully implemented, CAIR is expected to reduce emissions in these states by over 60% and 70% for NOx and SO_2, respectively, from 2003 levels. CAIR provides states the option of using a market-based cap-and-trade approach to achieve the required reductions through a two-phase compliance timeline. First phase reductions of NOx and SO_2 are required by 2009 and 2010, respectively. In addition, there will be an ozone season cap that further restricts NOx emissions within applicable areas from May 1 through September 30 of each year. Second-phase reductions for both NOx and SO_2 emissions must be implemented by 2015.

On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit found that CAIR was fundamentally flawed, and vacated the rule in its entirety. However, at that time, the court did not issue the mandate for the vacatur. On December 23, 2008, the Court modified the remedy and remanded CAIR, without vacatur, to the USEPA to modify the rule consistent with the court's July 11, 2008 decision, thereby preserving CAIR in its entirety.

Clean Air Visibility Rule (CAVR)

In 2005, the USEPA issued the Clean Air Visibility Rule (CAVR) to address regional haze issues associated with NOx, SO_2, and PM emissions. CAVR requires states to develop and execute SIP requirements to address visibility impairment in designated national parks and wilderness areas, known as mandatory Class I federal areas, with a national goal of zero impairment by 2064. Affected states, including Wisconsin, are required to submit SIPs for approval by the USEPA, including Best Available Retrofit Technology (BART) air pollution controls and additional measures, described below, necessary to reduce state contributions to regional haze. Implementation of CAVR reductions is scheduled to commence on January 1, 2014 with an initial demonstration of reasonable progress required in 2018.

Best Available Retrofit Technology (BART)

As part of CAVR, the USEPA issued guidelines for BART determinations in 2005 to address regional haze impacts attributed to a specific subset of emission sources that were placed into operation between 1962 and 1977. In accordance with the Wisconsin BART rule, codified under Chapter NR 433 of the Wisconsin Administrative Code, each source subject to BART shall install and operate BART as expeditiously as practicable, but in no event later than December 31, 2013. Emissions from EGUs of primary concern for BART and regional haze regulation include SO_2, NOx, and PM.

An EGU is "subject-to-BART" if air pollutant dispersion modeling suggests that it will contribute significantly to visibility impairment at a mandatory Class I federal area. Modeling by WDNR, as well as an independent consultant's analysis, has determined that Columbia Units 1 and 2 are "subject-to-BART" (see Appendix H. Once a source is classified as "subject-to-BART," a BART engineering analysis is used to establish a final BART determination. The USEPA has established presumptive BART emission limitations for coal-fired EGUs. WDNR uses these presumptive limits with site-specific considerations to determine individualized compliance plans for each applicable EGU. If a source justifies that the prescribed limitations are not cost-effective, alternative control levels may be established.

States participating in CAIR's cap-and-trade program can determine that CAIR equates to compliance with BART in regards to SO_2 and NOx emissions. Wisconsin is currently complying with BART via this "CAIR equals BART" methodology. The USEPA's pending revisions to CAIR create uncertainty regarding Wisconsin's compliance with BART. WDNR has recently confirmed that the "CAIR equals BART" provision of the Wisconsin BART rule still applies, however, as the federal CAIR program undergoes revisions directed by the court remand, the WDNR may revise NR 433 should the visibility improvements expected from the CAIR be diminished or delayed.

Haze Rule

WDNR has acknowledged that, in addition to BART, further emission reductions will likely be required to meet CAVR visibility improvement requirements. On January 9, 2009, the USEPA indicated that 37 states, including Wisconsin, failed to submit SIPs that adequately address all of the required elements of CAVR. These states have two years to provide SIPs that address these deficiencies; failure to do so will result in the USEPA issuing a FIP that will satisfy the requirements of CAVR. WDNR will likely submit its SIP, including a Haze Rule, to the USEPA for approval.

Future Carbon Dioxide Regulations

There is considerable public debate over potential domestic policy for the regulation of greenhouse gas (GHG) emissions, including carbon dioxide (CO_2). State and regional initiatives to address CO_2 emissions are under way that may affect the Applicants' service territories. Specifically, governors from nine Midwest states, including Wisconsin, signed the Midwestern Greenhouse Gas Reduction Accord in November 2007. Participants are expected to develop a proposed cap-and-trade agreement and a model rule including a suggested implementation period.

The Applicants acknowledge the potential of climate change and the forthcoming associated public policy. Accordingly, specific to the proposed Columbia emissions reduction project, sensitivity analyses have been performed by the EGEAS model. These analyses are described in Appendix C and include the monetization of carbon dioxide emissions.

3.2.5 Select Air Emission Compliance Plan

The air emission planning process creates cost-effective and feasible emission control strategies that consider available emission control technologies and their associated costs and performance. Emission reduction projects are chosen by matching projected future emissions against various environmental compliance scenarios and forecasted electricity demand. The environmental compliance scenarios considered in emissions planning include current federal and state air quality standards, as well as more stringent outcomes associated with future federal and state regulations. The selection of an air emission plan is completed on the basis of regulatory compliance, net present value of total cost, and feasibility of implementation and technology performance. The air emission planning process combines needed emission reductions, available emission controls, and other operational considerations to develop a long-term plan of multi-emission controls to install on specific generating units at specific points in time.

3.2.6 Implement Near-Term Tactical Responses for Regulatory Compliance

While long-term plans assist in understanding the sensitivity of proposed emission controls to differing environmental compliance scenarios and help prioritize investments in emission control equipment, shorter-term tactical plans aid in the selection of specific emission controls for detailed technical reviews, determine feasibility at a plant and unit-specific level, refine cost estimates, and update financial budgets. Shorter-term tactical plans span the immediate two to five-year period. The air emission planning process provides flexibility to address regulatory uncertainty, technology improvements, and other changing business conditions when planning emission control investments. Due to the significant construction lead time necessary to install major air pollution controls, implementation of the near-term tactical plan must occur as part of the longer-term strategy.

3.3 Project Need and Alternatives Analysis

3.3.1 Project Need

The installation of dry FGD, baghouse, and ACI systems on Columbia Units 1 and 2 for emissions reduction is both prudent and necessary for the following reasons:

- The proposed ACI and baghouse systems are mature and economical methods of reducing mercury emissions by 90% to meet NR 446 requirements.
- The proposed dry FGD system is expected to achieve a level of SO_2 control adequate to satisfy the most stringent unit-specific emission requirements presumed over the remaining economic life of the Units.
- The proposed dry FGD system mitigates market risk associated with relying on SO_2 allowances to meet CAIR requirements.
- The installation of the proposed dry FGD, baghouse, and ACI systems will provide optionality in addressing changes to environmental regulations.

- The proposed dry FGD and baghouse systems will significantly reduce $PM_{2.5}$ emissions and will contribute to maintaining NAAQS attainment in Columbia County and surrounding areas.
- The proposed dry FGD, baghouse, and ACI systems are more cost-effective than prematurely replacing the Units, as discussed in Section 3.3.2.

3.3.2 Alternatives Analysis

There is considerable uncertainty in current and developing environmental regulations that govern how coal-fired power plants can and will be operated in the future. In the alternatives analysis performed for this project, EGEAS was used to evaluate alternative emission compliance "Plans" for Columbia under alternative projected views, or "Futures." The alternative Futures generally explore future potential changes to greenhouse gas and other emission regulations, fuel and purchased power costs, and renewable portfolio standards (RPS). As part of the analysis, four Plans were evaluated under a total of ten Futures, resulting in forty scenarios that were examined. The use of scenario analysis allowed the Applicants to examine the relative cost-effectiveness and environmental attributes of alternative plans for Columbia.

The EGEAS analyses in this Application were performed jointly by the Applicants. Common assumptions were agreed upon in an effort to provide a consistent basis for comparison and compilation of results. The EGEAS Summary Report in Appendix C provides the results and corresponding discussion of this effort.

Three of the alternative Plans evaluated compliance with environmental regulations through the installation of emissions controls at Columbia by varying the type and timing of installed controls. The fourth Plan evaluated premature replacement of the facility. The four Plans are summarized as follows:

1) <u>Install Mercury and SO_2 Emission Controls (Base Case)</u>
Plan 1 includes the installation of dry FGD, baghouses, and ACI systems on Units 1 and 2 by 2013. Section 6 and Appendix B describe the specific control technologies considered, pros and cons of each technology as related to Columbia Units 1 and 2, and criteria for evaluation and selection.

2) <u>Install Mercury, SO_2, and NOx Emission Controls</u>
Plan 2 includes the mercury and SO_2 controls, including type and timing, as proposed in Plan 1. In addition, Plan 2 includes the installation of Selective Catalytic Reaction (SCR) on both Units in 2015 to meet any future environmental regulations that require further reductions in NOx emissions. The constructability of SCR systems on both Units has been evaluated and determined to be feasible in support of this Plan. The purpose of this Plan is to demonstrate the desirability of installing air emission controls if additional NOx controls are required. Plan 2 also corresponds to Columbia using a phased-in approach to mercury emission reductions as allowed for by NR 446.

3) Delayed Installation of Emission Controls
Plan 3 demonstrates the impact on the cost of installing the air emission controls identified in Plan 1 if it were possible to delay their installation without compromising compliance with environmental regulations. In Plan 3, the ACI and baghouse systems are delayed until 2015, the compliance deadline for NR 446 mercury reductions. The installation for the dry FGD system is delayed until 2018 based on the assumption that increasingly stringent environmental regulations, such as BART or the Haze Rule under CAVR, will mandate SO_2 controls at Columbia by 2018 at the very latest.

4) Premature Facility Replacement
Plan 4 includes the premature replacement of Columbia Units 1 and 2 at the end of 2013, instead of installing emission controls. The capacity and energy provided by Units 1 and 2 are modeled to be replaced by capacity and energy sources as identified in the economic expansion plan developed through EGEAS.

The EGEAS analyses corresponding to the four Plans above are summarized in Table 3 for Future 1, the base case without monetized CO_2. The PVRR values represent the combination of EGEAS results from each of the Applicants as well as differential from the proposed base case[5]. Detailed, owner-specific values are provided in Appendix C. Across the ten Futures, the EGEAS analyses showed an economic benefit of controlling the Units versus premature replacement in the range of $0.7 to $2.0 billion.

Table 3. EGEAS Analysis Results for Future 1

Compliance Plan	PVRR ($ MM)	Differential from Base Case ($ MM)
1. Install Mercury and SO_2 Controls (Base Case)	$ 33,061	
2. Install Mercury, SO_2, and NOx Controls	$ 33,372	$ 310
3. Delayed Installation of Emission Controls	$ 32,879	$ -182
4. Premature Facility Replacement	$ 34,577	$ 1,516

Delaying the installation of the emission control equipment at Columbia Energy Center reduces cost as measured by PVRR. Across all Futures, the PVRR of Plan 1 (SO_2 and mercury controls installed in 2013) is $95 to $186 million higher than Plan 3 (mercury and SO_2 controls installed in 2015 and 2018, respectively) depending on the assumed price for SO_2 allowances. In general, delaying installation will reduce PVRR because the assumed cost of purchasing SO_2 allowances is less than the cost of emissions controls.

However, a significant delay in the installation of the SO_2 emission controls results in increased risk. This increased risk, depending upon how it manifests itself, could eliminate a portion or all of the cost savings available from the delayed control

[5] A positive PVRR difference represents an increase in costs while a negative PVRR difference represents a decrease in costs.

installation. Significantly delaying control installation exposes the Applicants to additional risks including:

- Environmental Compliance Risk – While it is possible to comply with some SO_2 environmental regulations using allowances or via fleetwide averaging, several regulations, including BART, may require unit or facility-level compliance. Without installed controls at Columbia, compliance with these regulations may not be possible. Untimely installation of the controls may require the Applicants to modify operations through de-rating or temporary shutdown to achieve compliance until controls installation is complete. This could result in additional near-term fuel and purchased power costs for the Applicants.
- Allowance Market Risk – Delaying installation of the SO_2 emission controls will result in greater reliance on the use of purchased SO_2 allowances to comply with CAIR. The SO_2 allowance market price is uncertain and subject to rapid, unanticipated changes. While it is possible to use a hedging strategy to reduce the price uncertainty, installation of the controls will minimize the need to purchase SO_2 allowances and thus minimizes this risk. In addition, because of the recent uncertainty regarding CAIR's future, a general uncertainty exists regarding the allowance market itself.
- Construction Cost Risk – Delaying installation of the SO_2 emission controls exposes the Applicants to uncertain future construction costs. Installing controls sooner instead of delaying installation will provide flexibility to manage this risk.

The results of the EGEAS analyses can be summarized by the following observations and conclusions:

- Emission controls are cost-effective across all Futures, whereas prematurely replacing Columbia Units 1 and 2 is not economical.
- The phased-in multi-pollutant compliance strategy afforded by NR 446, which requires SO_2 and NOx reductions, is not an economically favorable alternative to 90% mercury emission reduction compliance by 2015.
- Installing controls remains cost-effective even if NOx controls (SCR) are required by future regulation when compared to premature replacement of the Units.
- Emission controls are cost-effective when CO_2 is monetized and provide a bridge to a carbon-constrained world while preserving optionality.
- Delaying controls presents a trade-off between cost savings and risk. While the analysis indicated delaying installation of the proposed controls reduces PVRR, delay also exposes the Applicants and ratepayers to increased risks associated with potential changes to environmental regulations, risks associated with increased reliance on the emissions allowance market, and risks associated with reduced schedule flexibility during construction.

3.4 Need and Alternatives Analysis Summary

The Columbia emissions reduction project serves to reduce mercury and SO_2 emissions at the Columbia Energy Center. Installation of these systems is essential to comply with NR 446 and other current state and federal emissions regulations, and to provide optionality in addressing future regulations. As further discussed in the EGEAS Summary Report in Appendix C, the proposed project is a necessary component of the Applicants' emission compliance strategies for the following reasons:

- Investment in the Columbia emissions reduction project will best position the facility to meet or exceed current and future emissions regulations regarding mercury and SO_2, as well as reduce fine particulate matter ($PM_{2.5}$) and acid mist.
- Investment in mercury and SO_2 emission controls at Columbia and continued operation of the plant, compared to premature replacement of Columbia, substantially reduces ratepayer revenue requirements for all views of the future contemplated.
- Investment in mercury and SO_2 emission controls at Columbia provides all three co-owners with a cost-effective, lower risk compliance approach that is responsive to the increasing stringency and uncertainty associated with achieving and maintaining compliance.
- Investment in mercury and SO_2 emission controls (and NOx emission controls if future regulations require it) to assure continued operation of the plant provides a bridge to a potential future carbon-constrained operating environment and preserves optionality to make cost-effective longer-term portfolio changes that may be needed for compliance with future greenhouse gas regulations.

4.0 Operating Parameters

The dry FGD, baghouse, and ACI systems for Columbia Units 1 and 2 will be designed to meet key operating parameters, including mercury and SO_2 removal. The following sections describe operations of these systems on Columbia Units 1 and 2.

4.1 Cost of Operations

Table 4 provides a preliminary breakdown of key fixed and variable operating parameters for the dry FGD, baghouse, and ACI systems on Columbia Units 1 and 2. The operating and maintenance estimates are based on information from vendors and on both Units burning the design coal. Fixed operating parameters are based on operating and maintenance typical of an SDA, baghouse and ACI system of this size and operating capability.

Table 4. Columbia Units 1 and 2 Dry FGD and ACI Key Operating Parameters

Operating Parameter	Columbia 1	Columbia 2	Units
Spray Dryer Absorber (SDA) and Baghouse			
Annual Capacity Factor	80	78	%
Flue Gas Flow Rate	2,600,000	2,400,000	acfm
Design SO_2 Removal Efficiency	90	90	%
SO_2 Removed[a]	0.522	0.545	lb/MMBtu
	10,500	10,500	tons/year
FGD Solids to Disposal[b]	17	16	tons/hr
Freshwater to Lime Slaker	140	135	gpm
Dilution Water to SDA	400	320	gpm
Lime Consumption	17,000	16,400	lb/hr
Power Requirement (SDA, Baghouse and ID fan)	8	8	MW
Additional Operating Personnel	7.5	7.5	FTEs
Activated Carbon Injection (ACI)			
Activated Carbon Consumption[c]	470	440	lb/hr
Design Mercury Removal Efficiency	90%	90%	%

a. SO_2 Removal shown in this table is based on the dry FGD system achieving 90% removal from baseline emissions. Baseline emissions were determined from 2005 – 2007 emissions data. Note that the other operating parameters presented in the table are based on the design coal.
b. Solids disposal includes ACI solids captured in the baghouse.
c. Activated carbon consumption is based on a 3 lb/MMacf injection rate of brominated activated carbon.

Fixed and variable operating costs are based on consumption rates presented in Table 4 and the following cost assumptions:

- FGD solids disposal: $40/ton
- Lime reagent: $105/ton
- Activated carbon: $2,200/ton
- Fresh water: $0.40/100 ft^3
- Operating personnel: $58/hr

The total annual operating costs (fixed and variable) for the dry FGD and ACI systems at the Columbia Energy Center are estimated to be approximately $20,600,000 for Unit 1 and $19,600,000 for Unit 2 (in 2007 dollars[6]).

4.2 Operating Characteristics

The installation of the dry FGD and ACI systems on Columbia Units 1 and 2 will affect operation of the Units. Significant operations that will be affected include the following:

Boiler Furnace Pressure Transients and ID Fans
The addition of the SDAs and baghouses on Units 1 and 2 is not expected to trigger the need for furnace reinforcement, based on analysis of the existing and future furnace pressures. Both Units currently operate with both FD and ID fans. Booster fans will be needed to overcome the additional pressure drop required to carry the flue gas through the proposed emission control equipment (approximately 11 in. w.g. across the SDA and baghouse, with additional pressure drop across the ductwork).

Process Control
The dry FGD and ACI systems require new controls to be added and integrated into the operator interface in the existing control room. Plant personnel will require training on all new equipment and controls.

Materials Handling System
Lime delivery and preparation will require operator involvement. The lime will be delivered as pebble lime and processed through slakers and classifiers to hydrated lime for use in the scrubbers. Additionally, activated carbon will be delivered to the site and stored in silos. Blowers will be used to inject the activated carbon into the ductwork.

Truck and Rail Traffic
Truck traffic will approximately double due to deliveries of lime, activated carbon, and removal of the dry FGD byproduct, based on consumption and production rates stated in Table 4. As activated carbon is currently used in the ACI system on Unit 2, the delivery plan for activated carbon to the site will not change. The ACI systems on Units 1 and 2

[6] Annual operating costs were estimated in 2007 dollars and do not include costs associated with the auxiliary power. In the EGEAS analysis accompanying this Application, the operating costs were escalated from 2007 dollars to year-of-occurrence dollars.

will require only a few truckloads of activated carbon delivered to the site per week. Rail traffic at the site will not be affected by operation of the dry FGD and ACI systems.

Plant Operating Personnel

For the purpose of estimating operating and maintenance costs, 15 new operating staff is assumed to be needed to operate the proposed emission control systems. Actual staffing levels will be determined by plant personnel at a later date.

Chemical Handling

Lime is required by the spray dryer system. It will be delivered in crushed or pebble form via enclosed truck trailers. The lime will be pneumatically conveyed from the truck to storage to minimize employee exposure. Similarly, activated carbon will be delivered by truck and conveyed pneumatically to storage.

Auxiliary Power Consumption

Approximately 8 MW of auxiliary power will be consumed by the dry FGD and ACI systems on each Unit, thus reducing the plant output for Units 1 and 2 by 16 MW. The auxiliary power is for operation of the SDA, baghouse, ACI blowers, and ID fan power required to overcome the pressure drop of the equipment and ductwork.

5.0 Description and Cost of Property Being Removed

The current project layout and general arrangement of the dry FGD and ACI systems at the Columbia Energy Center were developed to improve constructability, reduce length of equipment tie-in outages, and reduce relocation and demolition work. Based on preliminary engineering completed, the following major facilities are planned for demolition:

- Pipe bridge
- Fuel oil tank
- Two concrete flyash silos
- One loadout silo

The cost estimate for the Columbia emissions reduction project includes $1,000,000 for demolition and removal. The net book value of the equipment is under $19,000. No other existing equipment or structures are anticipated to be demolished or replaced as a part of this project. See Appendix A for further detail on the demolition plans.

6.0 Reduction Technology Selection

The following section is a synopsis of the emission control technology selection analysis. The complete analysis of these technologies, including a discussion of the pros and cons of their application at Columbia that form the basis of the decision for the technologies selected, can be found in Appendix B.

6.1 Technology Selection Process

The specific technologies chosen for mercury and sulfur dioxide (SO_2) emission reductions at Columbia Units 1 and 2 were determined by an analysis of the following parameters:

- Technologies capable of meeting the requirements of current and probable future regulations discussed in Section 3 of this Application.
- Available and proven technologies for emission reductions at units of comparable or larger size.
- Capability of technology to meet strict surface water mercury discharge standards or achieve zero liquid discharge.
- Technology and fuel compatibility.
- Reliable, long-term removal efficiencies achievable by each technology.
- Co-benefits and synergistic effects of multiple technologies for maximum multi-pollutant emission controls, notably SO_2 and mercury.
- Specific costs for each technology at Columbia Units 1 and 2.
- Implementation timeframes, particularly lead times and availability of critical components.
- Plant specific considerations (e.g. space or current plant operation and equipment constraints).

To address Wisconsin's mercury rule, NR 446, the following technologies were evaluated for mercury control according to the criteria listed above:

- Oxidizing Fuel Additive
- Activated Carbon Injection (ACI)

The mercury technologies chosen for further analysis are those that have demonstrated on a short-term basis the high-level of mercury control required by NR 446. ACI is assumed to be upstream of a particulate control device to capture the injected carbon and adsorbed mercury. The analysis at Columbia includes ACI upstream of the existing ESPs as well as upstream of new baghouses. The fuel additive is assumed to be a halogen compound (either chlorine or bromine) that is injected into the boiler to increase the amount of oxidized mercury available for capture and control. Fuel additives are included in this analysis because the coal fired at Columbia is low in these halogen compounds and the use of a fuel additive in conjunction with other emission control equipment can enhance the mercury removal capability of that equipment.

Based on site requirements and the evaluation criteria listed above, the following technologies were evaluated for SO_2 reduction:

- Wet FGD, Limestone with Forced Oxidation (LSFO)
- Dry FGD, Spray Dryer Absorber (SDA)
- Dry FGD, Circulating Fluidized Bed (CFB)

The technologies chosen for further analysis represent both wet and dry flue gas desulfurization (FGD) technologies and are among the most widely used in the electric utility industry for SO_2 emissions control. Wet FGD is assumed to use a limestone reagent with forced oxidation (LSFO). Both dry FGD technologies use a lime reagent to remove SO_2 from the flue gas and require a downstream particulate collection device, usually a baghouse, to accumulate the reaction products, unused reagent, and flyash for proper disposal.

6.2 Summary of Technology Selection

A dry FGD system consisting of an SDA with baghouse, and ACI for mercury removal are the technologies of choice for installation at Columbia Units 1 and 2. A CFB system has many of the same operational characteristics and benefits as an SDA, however, the CFB system is limited in vessel sizing and there is limited experience with this technology applied to PRB fired units at the time of evaluation. An LSFO system is effective at removing SO_2 but has a higher evaluated cost and produces mercury contaminated wastewater. The SDA, baghouse and ACI technologies were chosen for installation on Columbia Units 1 and 2 because these systems offer the following advantages:

- **Produces no mercury contaminated wastewater**. The dry FGD option produces a dry byproduct. There is no mercury contaminated wastewater stream; the mercury is captured and disposed of as solid waste. There is no wastewater containing other pollutants that would require treatment to meet discharge standards or maintain operational control of the system. This also eliminates the additional expense of wastewater treatment equipment.
- **Has superior capture and control of mercury.** An ACI system and baghouse are required to achieve 90% reduction in mercury emissions by 2015 in accordance with NR 446. The existing Unit 2 ACI system will be expanded to Unit 1 and the injection point for both Units will be upstream of the SDA vessels. This configuration takes advantage of the baghouse serving dual purposes: collecting the carbon and bound mercury; and collecting the solids from the SDA. The filter cake that forms on the bags improves the contact between the carbon and the mercury as the flue gas passes through the filter cake, thereby increasing the amount of mercury removed to 90%.
- **Is a commercially proven technology**. The use of ACI in conjunction with a baghouse for mercury control has undergone extensive demonstration testing and is considered to be the most commercially viable of mercury control technologies

even though there are few commercial scale installations and long-term removal efficiencies from this technology have yet to be established. The SDA and baghouse system for SO_2 control is well established in the utility industry and is best suited to units that fire coal with a sulfur content of 1.5 wt% or less. Because Columbia currently fires a PRB coal with a lower sulfur content, this technology allows for future fuel flexibility.

- **Provides cost-effective control.** A dry FGD system consisting of an SDA and baghouse can reliably achieve 90% reduction in SO_2 emissions. As previously stated, the ACI system and baghouse are required to achieve 90% mercury reduction in accordance with NR 446. The installation of an SDA, baghouse, and ACI system is economical, having a lower PVRR than premature replacement of the facility.
- **Utilizes the existing chimneys**. The flue gas exiting the dry FGD system is not saturated with water vapor. Therefore, chimney exit velocity requirements can be maintained and the potential for corrosion of the existing chimney liners is limited. This allows the existing chimneys to remain in operation, saving considerable project cost associated with constructing a new chimney.
- **Has fewer operational demands**. A dry FGD system does not consist of a large number of equipment items, due in large part to the dry nature of the process. The reduced amount of equipment and the dry nature of the byproduct translates to a limited auxiliary power requirement and reduced maintenance requirements. A dry FGD system also consumes less water because the flue gas is not saturated with water vapor.
- **Provides additional co-benefits.** The dry FGD system is very effective at capturing fine particulate matter such as $PM_{2.5}$ and acid mist. In addition, the installation of a baghouse with the SDA not only increases the achievable mercury removal with ACI, but also allows the carbon to be injected downstream of the existing ESPs and collected separately from the flyash, thereby maintaining beneficial reuse of flyash collected at Columbia.

7.0 Environmental Impacts/Permits

The proposed project location and preliminary site layout for the project are shown in Section 1, on Figures 1 and 2. The general site layout is shown in Attachment A.

7.1 Emissions Reductions

The Columbia emissions reduction project will significantly reduce mercury and SO_2 emissions from the Columbia Energy Center, thereby improving air quality and visibility in Wisconsin and mandatory Class I federal areas.

7.2 Proximity to Floodplains

The area chosen for the location of the Columbia emissions reduction project is not within a 100 year floodplain.

7.3 Information on Applicable Environmental Factors

Several environmental factors have been considered for the proposed emissions reduction project. Studies have been performed at the site, evaluating the presence of features that could be impacted by the project. The studies performed include the following:

- Archaeological and historic resources
- Threatened or endangered species
- Solid waste
- Water resources
- Wastewater discharge

Additional information is found in the following sections.

7.3.1 Archaeological and Historic Resources

There are no known archaeological or historic resources in the construction footprint of the project.

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7.3.2 Threatened and Endangered Species

A detailed analysis was performed on threatened/endangered species at the Columbia Energy Center as part of Public Service Commission Docket 6680-CE-170. Construction of the Columbia emissions reduction project will occur on already developed co-owned property with no adverse impacts to critical habitats for endangered, threatened, or special concern species. Appropriate Best Management Practices (BMPs) and erosion control techniques will be used to prevent impacts to habitats. Accordingly, no detrimental impact to threatened, endangered, or special impact species is expected.

7.3.3 Solid Waste

Currently, most of the bottom ash is beneficially reused. Flyash is sold as a useful by-product. The existing ESPs are expected to remain in operation after the addition of the dry FGD, baghouse, and ACI systems, allowing for continued beneficial reuse of the flyash[7]. No impact on the bottom ash marketability is expected. The proposed baghouse will collect dry FGD process particulates, including calcium salts, unused lime reagent, flyash and spent carbon from the ACI system. No market currently exists for this material. Accordingly, the volume of solid waste sent to landfill will increase.

7.3.4 Water Resources

To operate the proposed emission control systems, plant water consumption will increase. The lime slaking process will require approximately 275 gallons per minute (gpm) of high quality water such as well water. This will increase Columbia's well water usage from approximately 200 gpm currently to 475 gpm, which is well within the plant's permitted well water usage rate of 750 gpm. An additional 720 gpm of dilution water is required to cool the flue gas in the SDA vessel. This dilution water can be of a lower quality such as cooling pond water, ash pond water or other wastewater stream. The water quality of each source will need to be verified for its suitability for the process.

7.3.5 Wastewater Discharge

Columbia's wastewater discharge will not be affected by the addition of the proposed emission reduction systems because the dry FGD system operates without wastewater discharge. Water used in the dry FGD system is absorbed in the process and the spent reagent and particulate matter is collected in a baghouse and sent for disposal or recycled back to the absorber.

[7] The operation of the Unit 2 ACI system may initially prevent the beneficial reuse of flyash from Unit 2 since ACI residuals will be collected with the flyash in the ESP, thereby contaminating it and preventing its reuse. However, upon operation of the proposed baghouse on this unit, the baghouse will collect ACI residuals separate from the flyash collected in the ESP, eliminating any possibility of contaminating flyash once again allowing beneficial reuse of the flyash.

7.4 List of Permits and Approvals Needed

Table 5 provides a list of permits and approvals that may be required for the project.

Table 5. List of Possible Permits and Approvals

Agency	Reference	Permit/Plan/Approval/Report	Regulated Activity	Needed
Water Quality				
WDNR	NR 216 IAC 567 Chapter 60	Erosion Control Plan and Storm Water Management Plan for Construction Activities	Land disturbances greater than 1 acre	Prior to construction
WCOMM	COMM 60	Erosion Control Plan and Storm Water Management Plan for Construction Activities	Land disturbances greater than 1 acre	Prior to construction
WDNR	NR 216	SWPPP	Storm water management for industrial facilities. This may need to be updated for the new operation	Prior to operation
WDNR	NR 200	WPDES Discharge Permit	Tank containment and tank loading pad system discharge	Prior to construction
WDNR	NR 200	WPDES General Discharge Permit	Dewatering during construction	Prior to construction
WDNR	NR 200	WPDES General Discharge Permit	Hydrostatic testing of tanks	Prior to hydrostatic testing
WDNR	NR 142.06	Water Use Registration and Consumptive Use Permit	Increased water use	Prior to construction
Hazardous Materials				
USEPA	40 CFR Part 112	SPCC Plan	Temporary oil storage on-site for construction activities	Within 6 months of having oil on site (but realistically when oil arrives on-site)
USEPA	40 CFR Part 112	SPCC Plan	Additional chemical or fuel storage on-site supporting the newly constructed equipment	Within 6-months of operation but realistically by the time operation commences.
USEPA	40 CFR part 302	CERCLA Emergency Response Planning	Spill response of hazardous materials. We typically cover this in our SPCC plan.	Prior to chemicals being on-site
USEPA	40 CFR Part 355	EPCRA Emergency Response Planning	Spill response of hazardous materials. We typically cover this in our SPCC plan.	Prior to chemicals being on-site
USEPA	40 CFR Part 370	Initial Notification	Notification of lime stored onsite	Prior to chemicals being on-site
USEPA	40 CFR part 372	EPCRA Toxic Release Inventory Report	Disposition of chemicals used on site during construction and for the new operation need to be reported if used above applicable thresholds.	Calendar year reporting due July 1 of the following year
USEPA	40 CFR part 370	EPCRA Hazardous Chemical Inventory Report	Chemicals stored on-site during construction and new chemicals stored on-site for the new operation need to be reported if above applicable thresholds.	Calendar year reporting due March 1 of the following year
Air Quality				
USEPA	40 CFR part 72	Acid Rain Permit	Emission controls, rates, and averaging plans need to be updated if NOx or SO_2 emissions change.	Prior to operation.

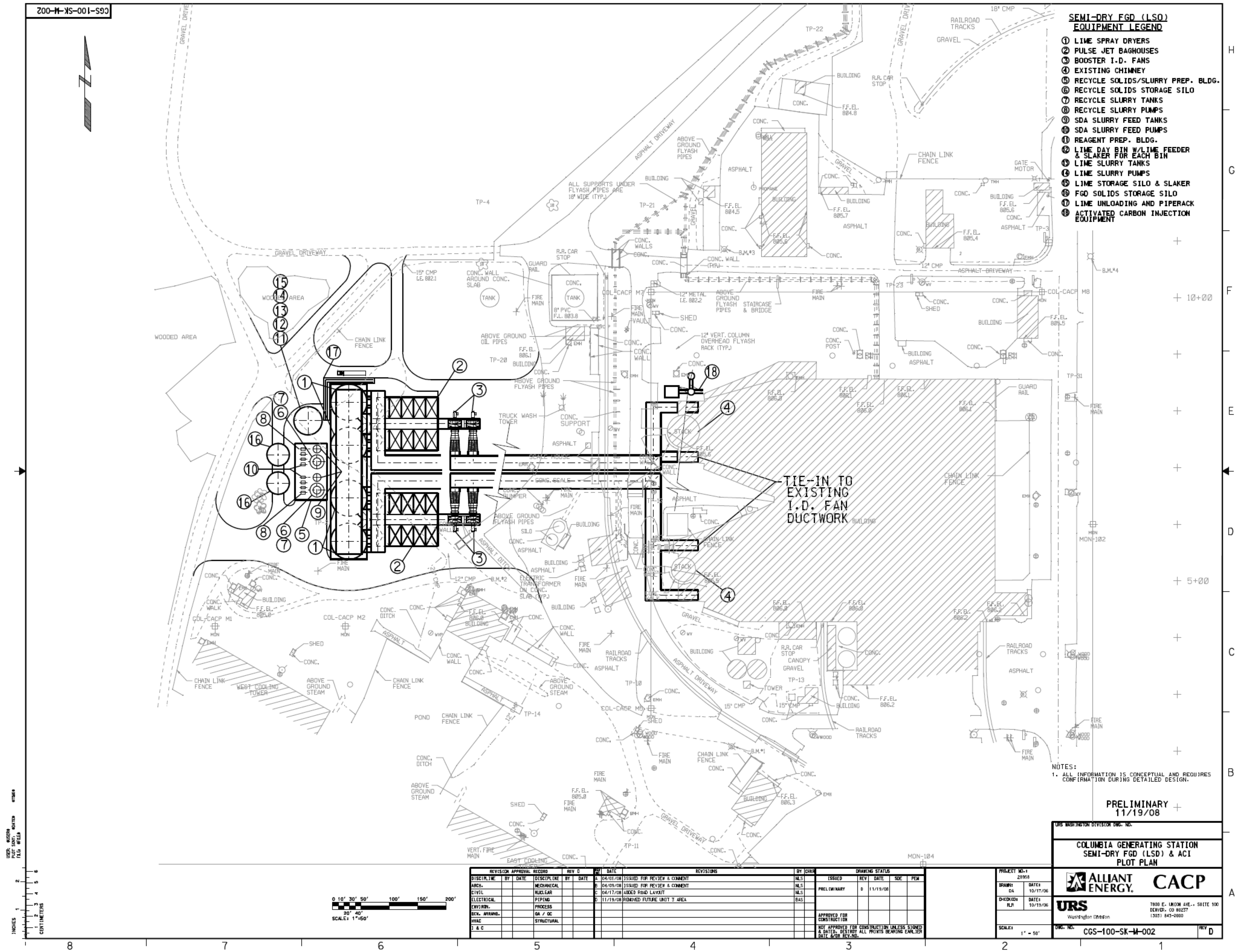
Agency	Reference	Permit/Plan/Approval/Report	Regulated Activity	Needed
WDNR	WAC NR 405 and 406	Construction Permit (NSR, PSD, etc)	New or increased emissions due to the modification	Prior to construction
WDNR	IAC 567 Chapter 22 WAC NR 407	Title V Operation Permit	Activities covered in construction permit need to be rolled into the Title V operating permit	Within time period specified in construction permit.
Tall Structures				
FAA	14 CFR Part 77	Notice of Proposed Construction or Alteration	Construction of new stacks or structures (cranes) 200 feet tall or within 20,000 feet of an airport.	Prior to construction
Solid Waste/Byproducts				
WDNR		Waste Disposal Authorization	Approval to dispose of new material in a landfill	Prior to disposal
WDNR		Byproduct Use Authorization	Approval for beneficial reuse	Prior to use
Local Approvals				
Municipality	City, county, village, etc.	Zoning Variance	Local approval for structures greater than 80 feet tall is required.	Prior to construction
Municipality	City, county, village, etc.	Local approvals for air quality, water quality, storm water, hazardous materials, etc.	Review municipal codes to determine if local environmental or construction requirements exist.	Prior to construction

8.0 Designation of Public Utilities and Others Affected

Columbia Units 1 and 2 are jointly owned by Wisconsin Power and Light Company (WPL), Wisconsin Public Service Corporation (WPS), and Madison Gas and Electric (MGE). WPL owns 46.2%, WPS owns 31.8%, and MGE owns 22% of Units 1 and 2 at the Columbia Energy Center. The installation of dry flue gas desulfurization (dry FGD), baghouses, and activated carbon injection (ACI) technologies on Columbia Units 1 and 2 will substantially reduce SO_2 and mercury emissions in the State of Wisconsin as well as improve conditions associated with regional haze in designated mandatory Class I federal areas. No other public utilities will be affected by this project.

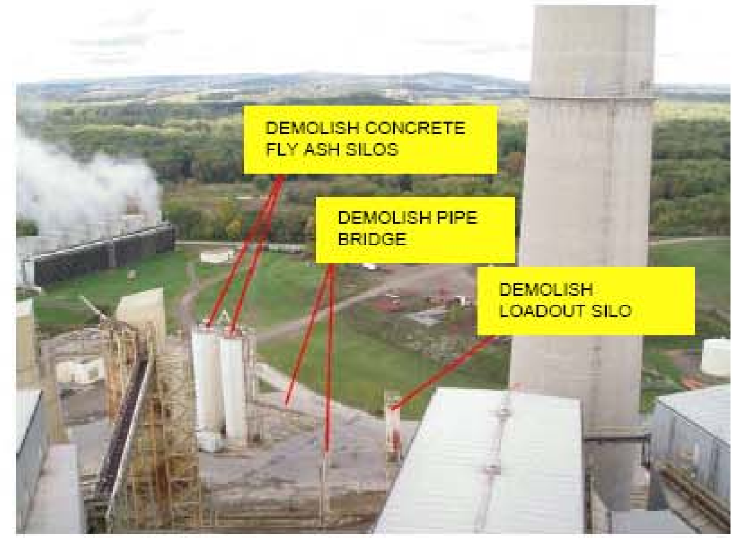
APPENDIX A

GENERAL SITE LAYOUT

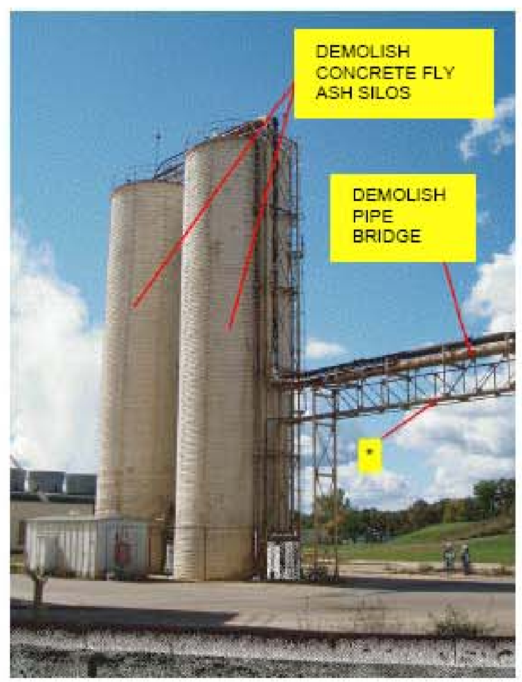

SEMI-DRY FGD (LSD) EQUIPMENT LEGEND
① LIME SPRAY DRYERS
② PULSE JET BAGHOUSES
③ BOOSTER I.D. FANS
④ EXISTING CHIMNEY
⑤ RECYCLE SOLIDS/SLURRY PREP. BLDG.
⑥ RECYCLE SOLIDS STORAGE SILO
⑦ RECYCLE SLURRY TANKS
⑧ RECYCLE SLURRY PUMPS
⑨ SDA SLURRY FEED TANKS
⑩ SDA SLURRY FEED PUMPS
⑪ REAGENT PREP. BLDG.
⑫ LIME DAY BIN W/LIME FEEDER & SLAKER FOR EACH BIN
⑬ LIME SLURRY TANKS
⑭ LIME SLURRY PUMPS
⑮ LIME STORAGE SILO & SLAKER
⑯ FGD SOLIDS STORAGE SILO
⑰ LIME UNLOADING AND PIPERACK
⑱ ACTIVATED CARBON INJECTION EQUIPMENT
TIE-IN TO EXISTING I.D. FAN DUCTWORK
NOTES:
1. ALL INFORMATION IS CONCEPTUAL AND REQUIRES CONFIRMATION DURING DETAILED DESIGN.
PRELIMINARY 11/19/08
COLUMBIA GENERATING STATION SEMI-DRY FGD (LSD) & ACI PLOT PLAN
ALLIANT ENERGY
CACP
URS
CGS-100-SK-M-002
SCALE: 1" = 50'

CGS-100-SK-M-079

FUEL OIL TANK
SEE NOTE 2



SILOS AND PIPE BRIDGE
SEE NOTES 3, 4 & 5



CONCRETE SILOS AND PIPE BRIDGE
SEE NOTES 3 & 4

LOADOUT SILO
SEE NOTE 5

DEMOLITION NOTES:

1. ALL WORK SHALL BE IN ACCORDANCE WITH DEMOLITION SPECIFICATION 28958-100-15-G-S01 AND COORDINATED WITH THE COMPANY (PLANT SUPERINTENDENT).
2. DEMOLITION OF FUEL OIL TANK SHALL INCLUDE:
   PIPING AND PIPE SUPPORTS
   ELECTRICAL POWER CONDUIT AND WIRING
   DIGITAL SIGNAL CONDUIT AND WIRING
   FUEL OIL TANK
   STRUCTURAL STEEL, PLATFORMS AND LADDERS
   ABOVE GROUND CONCRETE SUPPORT PAD(S)
   UNDERGROUND FOUNDATIONS SHALL BE ABANDONED IN PLACE
3. DEMOLITION OF CONCRETE FLY ASH SILOS SHALL INCLUDE:
   PIPING AND PIPE SUPPORTS
   ELECTRICAL POWER CONDUIT AND WIRING
   DIGITAL SIGNAL CONDUIT AND WIRING
   CONCRETE FLY ASH SILOS
   STRUCTURAL STEEL, PLATFORMS AND LADDERS
   ABOVE GROUND CONCRETE SUPPORT PAD(S)
   UNDERGROUND FOUNDATIONS SHALL BE ABANDONED IN PLACE
4. DEMOLITION OF PIPE BRIDGE SHALL INCLUDE:
   ELECTRICAL POWER CONDUIT AND WIRING *
   DIGITAL SIGNAL CONDUIT AND WIRING *
   PIPE BRIDGE
   ABOVE GROUND CONCRETE SUPPORT PAD(S)
   UNDERGROUND FOUNDATIONS SHALL BE ABANDONED IN PLACE
5. DEMOLITION OF LOADOUT SILO SHALL INCLUDE:
   PIPING AND PIPE SUPPORTS
   ELECTRICAL POWER CONDUIT AND WIRING *
   DIGITAL SIGNAL CONDUIT AND WIRING *
   LOADOUT SILO
   STRUCTURAL STEEL, PLATFORMS AND LADDERS
   ABOVE GROUND CONCRETE SUPPORT PAD(S)
   UNDERGROUND FOUNDATIONS SHALL BE ABANDONED IN PLACE
   REROUTING THE ELECTRICAL POWER AND DIGITAL SIGNAL CONDUIT AND WIRING ASSOCIATED WITH THE NEARBY SCALE AND SCALE HOUSE
6. SEE DWG. CGS-100-SK-M-078 FOR DEMOLITION PLOT.
7. * THE CONTRACTOR MUST REROUTE THE CONDUIT AND WIRING REQUIRED FOR THE SCALE AND SCALE HOUSE OPERATION THAT IS RUN ON THE PIPE BRIDGE AND SILO SUPPORT STEEL DESIGNATED TO BE REMOVED. THE REROUTE NEEDS TO BE DONE PRIOR TO ANY DEMOLITION AND COORDINATE WITH THE COMPANY.

WASHINGTON GROUP INTERNATIONAL DWG. NO. 100-16-11-700-002

COLUMBIA AQCS PROJECT (CST)
DEMOLITION
NOTES & PHOTOS

ALLIANT ENERGY. CACP

Washington Group International

DWG. NO. CGS-100-SK-M-079 REV. B

APPENDIX B

EMISSIONS REDUCTION TECHNOLOGY SELECTION

Appendix B Emissions Reduction Technology Selection

B.1 Technology Selection Process

The specific technologies chosen to accomplish the goal of mercury and sulfur dioxide (SO_2) emission reductions at Columbia Units 1 and 2 was determined by an analysis of the following parameters:

- Technologies capable of meeting the requirements of current and probable future regulations discussed in Section 3 of this Application.
- Available and proven technologies for emission reductions at units of comparable or larger size.
- Capability of technology to meet strict surface water mercury discharge standards or achieve zero liquid discharge.
- Technology and fuel compatibility.
- Reliable, long-term removal efficiencies achievable by each technology.
- Co-benefits and synergistic effects of multiple technologies for maximum multi-pollutant emission controls, notably SO_2 and mercury.
- Specific costs for each technology at Columbia Units 1 and 2.
- Implementation timeframes, especially lead times and availability of critical components.
- Plant specific considerations (e.g. space or current plant equipment constraints).

Capturing mercury from the flue gas of electric generating units (EGUs) is a relatively new area of technology development. Despite the significant advancements made in the last several years, long-term removal efficiencies have not been established for many of the technologies under development. Of the many mercury control technologies in development, only a few have demonstrated on a short-term basis the high level of mercury control required by Wisconsin rule NR 446. The following technologies were selected from among those demonstrating a level of mercury control for evaluation according to the criteria listed above to address compliance with Wisconsin's mercury rule, NR 446, at Columbia:

- Oxidizing Fuel Additive
- Activated Carbon Injection (ACI)

Activated carbon injection is assumed to be upstream of a particulate control device to capture the injected carbon and adsorbed mercury. The analysis at Columbia includes ACI upstream of the existing electrostatic precipitators (ESPs) as well as upstream of new baghouses. Activated carbon injection is considered to be the most commercially viable technology for mercury control. It has undergone the most demonstration testing to date, and there are a few full-scale installations that are collecting long-term removal efficiency data. The fuel additive is assumed to be a halogen compound (either chlorine or bromine) that is injected into the boiler to increase the amount of oxidized mercury available for capture and control. Fuel additives are included in this analysis because the coal fired at Columbia is low in these halogen compounds and the use of a fuel additive in conjunction with other emission control equipment can enhance the mercury removal capability of that equipment.

There are many technologies that have undergone development over the last several decades to scrub SO_2 from power plant flue gas emissions. These technologies represent a wide variety of sorbent types, process configurations and removal mechanisms; however, many of these technologies do not meet the criteria of being commercially available and proven technologies. Based on site requirements and the evaluation criteria listed above, the following technologies were evaluated for SO_2 emissions reduction:

- Wet FGD, Limestone with Forced Oxidation (LSFO)
- Dry FGD, Spray Dryer Absorber (SDA)
- Dry FGD, Circulating Fluidized Bed (CFB)

The technologies chosen for further analysis represent both wet and dry FGD technologies and are among the most widely used in the electric utility industry for SO_2 emissions control. Wet FGD is assumed to use limestone with forced oxidation (LSFO). There are several different absorber designs offered by wet FGD vendors, but operating performance is similar for all of them; therefore, a generic open spray tower is assumed for this analysis. Dry FGD technologies can use either a spray dryer absorber (SDA) or circulating fluidized bed (CFB) absorber, both of which use a lime reagent to remove SO_2 from the flue gas. Both dry technologies require a downstream particulate control device, usually a baghouse, to accumulate the reaction products, unused reagent, and flyash for proper disposal.

Dry Sorbent Duct Injection was also initially considered for SO_2 control. The effectiveness of dry sorbent injection is dependent upon the type of sorbent, injection location, and system operating parameters. The most common sorbents are either sodium-based (such as trona) or calcium-based (such as lime) reagent, which can be injected at various points in the flue gas path downstream of the boiler. Dry Sorbent Duct Injection has not been demonstrated on units comparable in size to Columbia Units 1 and 2. In addition, injection rates for duct injection are typically two to three times that used for either a wet or dry FGD system, resulting in increased operating costs. In the case of a sodium-based reagent such as trona, the reagent costs are considerably higher then that of a calcium-based reagent. The typical range of SO_2 removal for duct injection is in the range of 40-70%, which may be insufficient SO_2 removal to comply with environmental regulations at Columbia. For these reason, dry sorbent injection was not included in any further analyses.

B.2 Evaluated Mercury Technologies

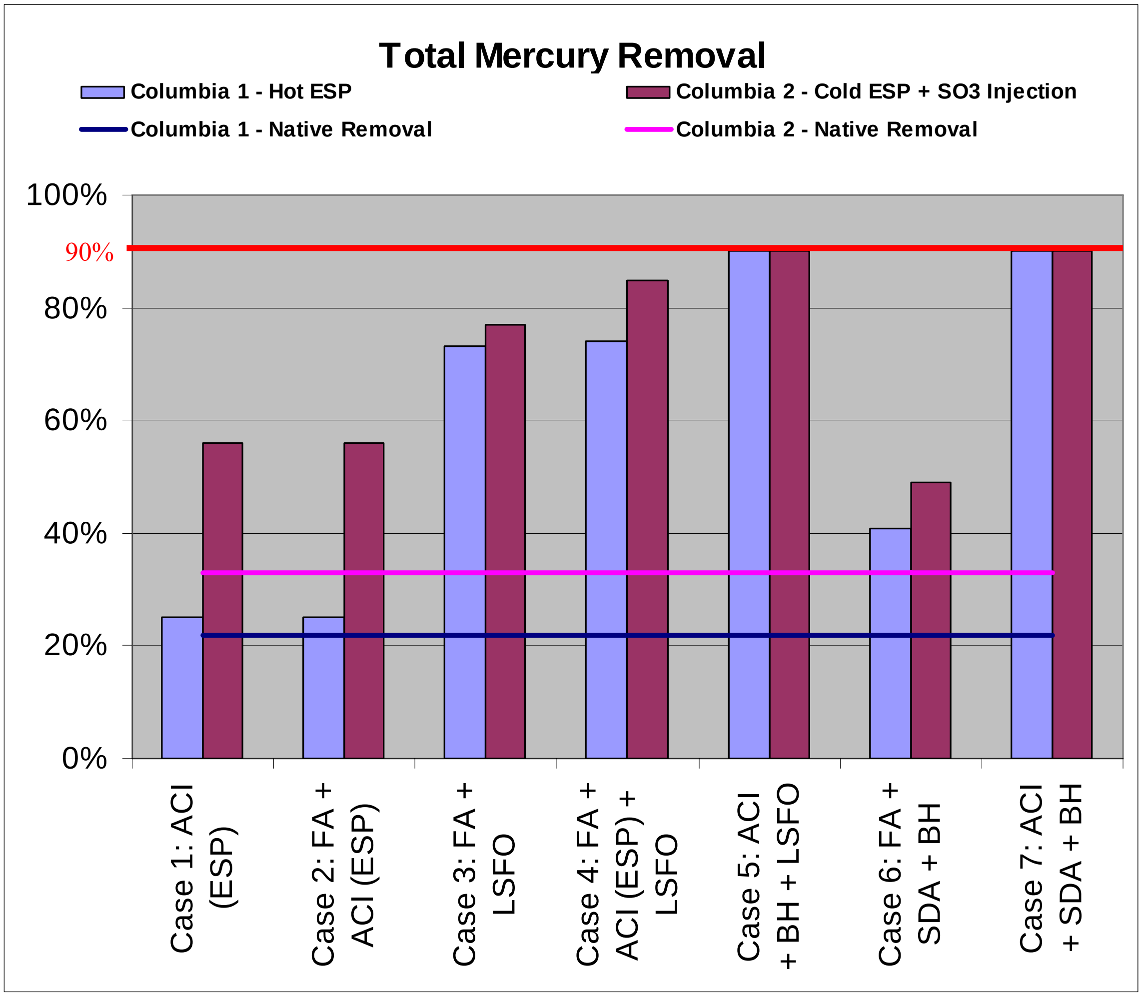
An ACI system was installed upstream of the ESP on Columbia Unit 2 in 2008 as described in the letter to the PSCW found in Appendix G. This ACI system was installed to reduce mercury emissions by 2010 in compliance with NR 446, however, it is insufficient to meet the 90% mercury reduction requirement in NR 446. Based on the criteria that Columbia Units 1 and 2 need to achieve 90% total mercury removal, expanding the use of ACI to Unit 1 and the use of a fuel additive in both Units were identified as two technologies that could be used in combination with the evaluated SO_2 technologies to achieve this goal. Figure B1 shows the seven cases evaluated followed by a table comparing the predicted cumulative performance for each combination of technologies, including native removal. Since the CFB is similar to as SDA in regards to configuration and mercury removal, only the SDA is evaluated in this section.

Mercury removal for any given technology has been shown to be variable from site to site and dependent upon plant operating conditions. The mercury removal efficiencies presented here are predicted results based on published demonstration testing.

<u>Case 1 – ACI with Existing ESP</u>
Predicted mercury removal efficiency based on demonstration tests done on units other than Columbia using ACI upstream of a cold-side ESP would be 40% to 70% with standard activated carbon for units firing PRB fuel. Higher removal efficiencies are possible with a halogenated (treated/brominated) carbon. The removal efficiency would be much lower for carbon injected upstream of a hot-side ESP, as would be the case for Columbia Unit 1, due to the substantially decreased reactivity of the carbon at higher temperatures.

Preliminary field testing on units other than Columbia also indicate that a high level of sulfur present in the flue gas interferes with the ability of the carbon to react with the mercury, thereby decreasing the removal efficiency. This data suggests that the mercury removal across Columbia Unit 2 ESP would be diminished because of the use of sulfur trioxide (SO_3) to condition the flyash and facilitate its removal in the ESP.

<u>Case 2 – Fuel Additive and ACI with Existing ESP</u>
The addition of an oxidizing fuel additive will increase the amount of oxidized mercury in the flue gas, which should be easier to capture with carbon injection. Theoretically, the mercury removal should increase from that of Case 1 with the addition of an oxidizing fuel additive. At the writing of this Application, however, the Applicants are not aware of any data to suggest what actual increase in mercury removal oxidizing fuel additives will have across a hot-side ESP and/or a cold-side ESP with SO_3 conditioning.



Columbia 1 & 2 Configuration Descriptions	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Technology							
Oxidizing Fuel Additive (FA)		X	X	X		X	
Activated Carbon Injection (ACI)	X	X		X	X		X
Baghouse (BH)					X	X	X
Spray Dryer Absorber (SDA)						X	X
Limestone Forced Oxidation (LSFO)			X	X	X		
Overall Mercury Removal, %							
Unit 1	25	25	73	74	90+	41	90+
Unit 2	56	56	77	85	90+	49	90+

Figure B1. Total Mercury Removal Efficiency From Coal to Stack by Technology Configuration

Case 3 – Fuel Additive and LSFO

Although an oxidizing fuel additive increases the amount of oxidized mercury in the flue gas that can be captured by an LSFO, it is not sufficient to achieve 90% removal. An LSFO system is expected to remove 90% of the oxidized mercury that enters the absorber, however, not all of the oxidized mercury remains in the LSFO liquor. Recent testing demonstrated that mercury captured in the LSFO liquor can react to form more elemental mercury and be reemitted with the exiting flue gas. To achieve 90% total mercury removal, 100% of the total mercury would have to be oxidized and have 90% removed by the LSFO system. Additionally, there would have to be zero re-emission of the mercury from the LSFO liquor. These conditions would be very difficult to maintain on a long term basis to achieve the required 90% mercury reduction.

Case 4 – Fuel Additive, ACI with Existing ESP, and LSFO

Even with the addition of ACI to the combination of an oxidizing fuel additive and LSFO, the predicted performance is expected to be below the required 90% removal. The activated carbon would be injected upstream of the existing ESP. The oxidized mercury would be removed more efficiently by the injected activated carbon whereby a smaller amount of oxidized mercury would be passed to the LSFO scrubber for removal.

Injecting activated carbon upstream of the existing ESPs at Columbia would also result in potential contamination of the flyash, reducing the options for beneficial reuse of the flyash. In addition, the station would also incur the cost of having to dispose of the contaminated flyash in a landfill.

Case 5 – ACI, Baghouse, and LSFO

The potential loss of flyash reuse in Case 4 could be prevented by installing a TOXECON I system (see Appendix F). The system, which consists of activated carbon injection with a compact hybrid particulate collector (COHPAC, baghouse), would be installed between the ESP and the LSFO. Since the carbon would be injected after the flyash is collected in the ESPs, the flyash would not be contaminated and beneficial reuse would be maintained. More importantly, however, TOXECON I has been demonstrated to achieve +85% mercury removal. An integral part of the TOXECON I system is the COHPAC baghouse, which provides the surface area for collecting the activated carbon. The filter cake that forms improves the contact between the carbon and the mercury as the flue gas passes through the filter cake thereby increasing the amount of mercury removed. The COHPAC baghouse comes at significant capital cost to the installation of the LSFO system because the COHPAC is not required as part of the SO_2 removal process. Operating costs are impacted as well due to the increased pressure drop across the baghouse.

Case 6 – Fuel Additive, SDA, and Baghouse

The addition of an oxidizing fuel additive in combination with an SDA and baghouse system would not provide sufficient mercury removal. The increased amount of oxidized mercury resulting from the fuel additive would facilitate an increase in the removal of oxidized mercury because it is more easily captured on any unburned carbon or flyash.

The SDA and baghouse system, however, has a low native capture associated with it, therefore, the increased mercury removal would not be substantive.

Case 7 – ACI, SDA, and Baghouse
This case is similar in configuration and mercury removal capability to that of Case 5. The major difference is that since a baghouse is installed as part of a dry FGD system, a majority of the cost associated with a TOXECON I system is eliminated. Only an ACI system is needed to take advantage of the presence of the baghouse to achieve 90% mercury reduction. When used in conjunction with an SDA and baghouse system, the activated carbon is injected upstream of the spray dryer, providing a long residence time for the carbon to mix and react with the mercury in the flue gas prior to collection in the baghouse. This arrangement is capable of achieving the requisite 90% mercury removal efficiency.

B.3 Evaluated FGD Technologies

B.3.1 Limestone Forced Oxidation

The Limestone with Forced Oxidation (LSFO) system has many positive aspects to its design and operation that recommend it for consideration at Columbia Units 1 and 2, including:

- LSFO was one of the first technologies developed to remove SO_2 from boiler flue gas and is currently the most commonly used technology.
- The electric utility industry has vast experience with LSFO.
- Vessel designs have advanced over the past 5-10 years, and a single vessel capable of treating 1,000 MW of flue gas has been demonstrated with high reliability.
- Vendors are guaranteeing performance of +95% SO_2 removal.
- LSFO has demonstrated high SO_2 removal efficiency across a broad range of fuels and flue gas flow rates.
- Limestone has a lower reagent cost than lime reagent.
- Gypsum byproduct can be beneficially reused.

Further analyses of the LSFO system, including its impact on plant operations and other environmental considerations, are discussed in the following sections.

Particulate Emissions

The LSFO system would be installed downstream of the existing ESPs on Columbia Units 1 and 2. Operation of the LSFO system would not affect the performance of these devices. As shown in Figure B2, ESPs are effective at capturing particulates with a diameter of 2 microns and larger, however, their ability to capture particulates with a diameter of less than 2 microns, which comprises most of $PM_{2.5}$, is greatly diminished when compared to a baghouse.

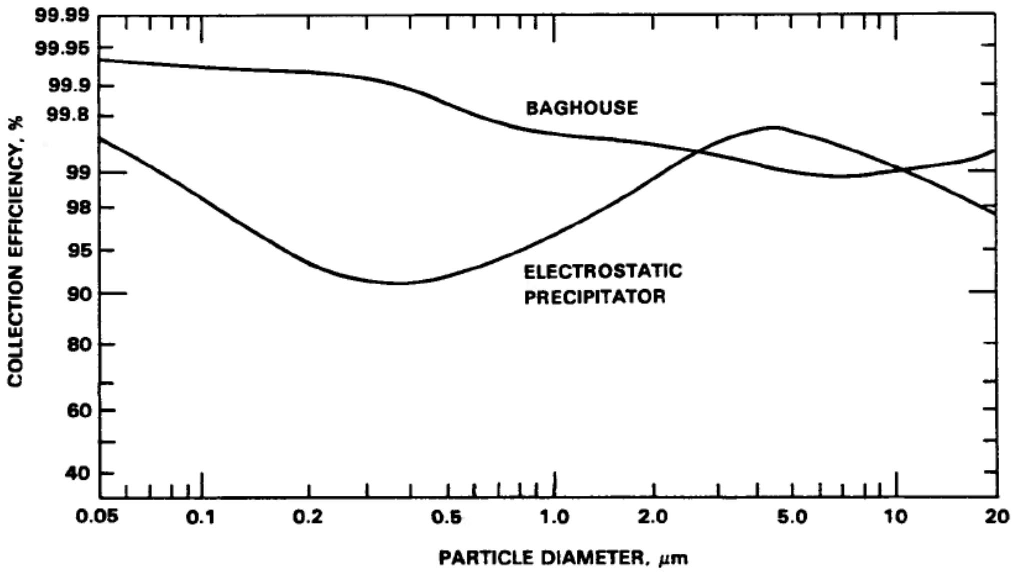


Figure B2. Particle Diameter Effect on Collection Efficiency for a Baghouse and ESP[8]

Mercury

An LSFO system can achieve up to 90% removal of oxidized mercury, while elemental mercury will pass through the scrubber vessel. The oxidized mercury ends up in the LSFO liquor, which then partitions between the gypsum and effluent water during the dewatering process. The mercury in the effluent water can be removed in a standard physical/chemical wastewater treatment process in which most of the mercury ends up in the sludge, however, some will remain in the wastewater discharge stream. Recent testing demonstrated that mercury captured in the wet FGD liquor can react to form more elemental mercury and be reemitted with the exiting flue gas. Additives and instrumentation have been developed to reduce this potential for reemission. PRB fuel has very little oxidized mercury, however, the use of fuel additives to oxidize additional mercury in the coal to subsequently achieve greater overall mercury reduction using a wet scrubber has not been demonstrated commercially over a long time period.

Wastewater Treatment/Discharge

The LSFO wastewater stream will need to be treated to maintain proper operation of the system as well as to meet discharge standards, especially for mercury. As stated above, an LSFO system will capture up to 90% of the oxidized mercury present in the flue gas. When the gypsum byproduct is dewatered, a portion of the mercury will be retained in the gypsum solids and associated moisture content, with the remainder in the effluent from the dewatering process. Mercury concentrations in the effluent water will depend on the amount of oxidized mercury in the flue gas and the blowdown rate. If a fuel

[8] "Baghouses for the Electric Utility Industry, Volume 1"; EPRI Publication No. CS-5161; prepared by Southern Research Institute; 1988 pg. 1-4.

additive is used to increase the amount of oxidized mercury in the flue gas that is available for capture, as would be needed at Columbia to approach 90% mercury removal, then the concentration of mercury in the effluent water will be higher.

WDNR has designated the Wisconsin River as being mercury impaired and has established strict prohibitions on the mercury levels in any discharge to mercury impaired surface waters. The presence of mercury in the LSFO effluent would make it extremely difficult to permit. Any effluent would likely have to treated before being discharged, requiring the additional cost of a wastewater treatment facility. The only wastewater treatment system that would meet the mercury discharged standard is a Zero Liquid Discharge (ZLD) system. ZLD is an emergent technology with only one commercial scale installation (in Italy that has been operational for less than one year) and has a track record of problems during demonstration testing in the U.S.

Other Operating Considerations

The following are additional operating considerations of an LSFO system:

- Water requirement – LSFO is a wet FGD system that by definition lowers the flue gas temperature within the absorber vessel to the saturation point (co-existence of vapor and liquid phase of water); typically around 130°F. Water is used to cool the flue gas to the saturation temperature, therefore, an LSFO system will have a higher water usage rate than a dry FGD system.
- Stack Plume Visibility – since the flue gas is saturated when it exits the LSFO absorber vessel, a heavy steam plume will be visible at the stack exit during all ambient conditions due to the lower temperature of the flue gas. The steam plume will also have less buoyancy than higher temperature stack gases, resulting in a tendency to fold downward as it exits the stack. Reheat systems have been used in the past to maintain dry stack conditions, however, they are very expensive to operate and have a negative effect on the plant heat rate. Additional plume visibility can result from condensable particulate matter such as sulfuric acid mist, which is generated when SO_3 produced during coal combustion combines with water vapor in the flue gas and then is cooled below the sulfuric acid dew point. Wet FGD systems typically remove 30-50% of the inlet SO_3/acid mist; the remainder can result in an acid mist plume exiting the stack.
- Chimney – due to the saturated and acidic nature of the flue gas, a new chimney would need to be constructed (adding cost to the installation of an LSFO system) to prevent corrosion of the chimney liner and to meet exit velocity requirements.
- Power Requirements – an LSFO system will have a higher auxiliary power requirement than a dry system. A large portion of the power requirement is due to the multiple large liquid recycle pumps necessary to recycle the limestone slurry within the absorber to achieve good gas-to-liquid contact and SO_2 removal. The auxiliary power requirement is increased further with the addition of a baghouse to the system to meet the required mercury reductions.

- Maintenance – The operating and maintenance requirements for a wet FGD system are significantly higher than a dry FGD system due to the large recycle pumps and dewatering equipment.

B.3.2 Spray Dryer Absorber

Spray dryer absorbers are best suited for EGUs approximately 600 MW or less that fire low sulfur coals, such as Units 1 and 2 at the Columbia Energy Center. The SDA system can typically scrub coals with a maximum sulfur content of 1.5 weight % sulfur. The SDA system has the ability to maintain approximately 90% SO_2 removal on a long term average basis. Columbia fires Powder River Basin (PRB) coal. The sulfur content of PRB can range as high as 0.80% by weight, which is within the operational range of the SDA system. The SDA vessels are limited to treating 300 MW of flue gas in a single vessel, therefore, two vessels would need to be installed per unit at Columbia. There is no market at this time for the beneficial reuse of the SDA byproduct, which is a mixture of calcium salts, unused reagent and flyash.

Further analysis of the SDA system beyond its SO_2 removal abilities and the impact of such a system on Columbia plant operations and other environmental impacts is discussed by topic in the following sections.

Particulate Emissions

The installation of an SDA for SO_2 control requires the presence of a downstream particulate control device to capture the reaction products from the SDA vessel. An existing particulate control device can be used; however, it is more common to install a new baghouse to capture the dryer solids due to the fact the existing particulate control devices are often ESPs, which were not designed to handle the additional particulate loading of the dryer solids. The installation of a new baghouse for each unit at Columbia has the added benefit of allowing the existing ESPs to remain in operation to collect the flyash separate from the dryer solids, thereby preserving the flyash for beneficial reuse at Columbia and preventing the additional expense of disposing of the mixed SDA solids and flyash. The downstream baghouse may provide an additional co-benefit of capturing $PM_{2.5}$.

Mercury

The SDA and baghouse system has a certain amount of native mercury capture associated with it, albeit the capture is very low. The real benefit of the SDA and baghouse system for mercury removal comes from using the system in conjunction with ACI upstream of the SDA vessel. The benefit of such an arrangement is three-fold: (1) injection of the activated carbon upstream of the SDA provides a long residence time for the carbon to mix and react with the mercury in the flue gas prior to collection in the baghouse; (2) the filter cake that builds up on the baghouse bags provides additional reaction surface for greater mercury removal; and (3) by using the baghouse associated with the SDA to collect the carbon, the existing ESPs can be left in place to collect the flyash for beneficial reuse.

Wastewater Treatment

The SDA process is considered a semi-dry process. Water, introduced into the system via lime slurry and dilution water, is used to aid in the reaction of the lime and SO_2 and control the temperature of flue gas at the outlet of the SDA. All water introduced into the SDA vessel is evaporated upon contact with the hot flue gas and exits the system as vapor with the flue gas. The only waste stream from the system is the dry solids, a majority of which are collected in the baghouse. A small amount of dry solids are collected at the bottom of the SDA vessel. The dry solids waste eliminates the added expense of a wastewater treatment system as well as the concern of mercury and other regulated contaminates discharged to surface waters.

Other Operating Considerations

- Water – An SDA consumes less water than a wet FGD system because the flue gas is cooled to approximately 30 degrees above the saturation temperature.
- Stack Plume Visibility – Because the flue gas exiting the stack is unsaturated, a steam plume may not be visible under some atmospheric conditions. However, when ambient temperatures are low enough, a steam plume from a dry scrubber can also appear. Other condensable particulate matter such as sulfuric acid mist, which is produced by the combination of SO_3 generated during combustion and water vapor present in the flue gas, can lead to a visible plume from the stack. Dry FGD systems are capable of reducing acid mist by +98%, thereby virtually eliminating a visible acid mist plume.
- Chimney – the existing chimney can be reused because the flue gas is not saturated, therefore, corrosion and exit velocity are not of much concern.
- Power Requirements – A dry FGD system consisting of an SDA and baghouse consumes less auxiliary power than a wet FGD system. Although an SDA and baghouse have a greater pressure drop than a wet FGD system due primarily to the baghouse, the increase in fan power required to overcome this pressure drop is more than offset by the large recycle pumps required by a wet system.
- Maintenance – the dry byproduct from the SDA can be handled by conventional flyash systems, resulting in the elimination of dewatering equipment and a reduction in the associated maintenance. Maintenance requirements are further decreased due to the elimination of large recycle pumps.

B.3.3 Circulating Fluidized Bed

The Circulating Fluidized Bed (CFB) absorber system is another dry FGD technology that was considered for control of SO_2 emissions at the Columbia Energy Center. A CFB system has many of the same advantages of an SDA over a wet FGD system, such as:

- High mercury removal efficiency with carbon injection.
- No wastewater treatment required.
- Greater removal of $PM_{2.5}$ with the presence of a baghouse.
- Preservation of the beneficial reuse of flyash by installing a new baghouse to collect the dryer solids and allowing the existing ESPs to remain in operation.
- Lower auxiliary power consumption.
- Less equipment installed resulting in an easier system to operate and maintain.
- Cheaper materials of construction.

In some cases the CFB may be chosen over the SDA technology due to the following characteristics of the CFB:

- A CFB can typically handle higher inlet concentrations of SO_2 and maintain higher reduction efficiencies than the SDA.
- A CFB is simpler to operate than an SDA because rotary atomizers are not required, eliminating a major piece of rotating equipment. Additionally, the hydrated lime reagent is injected into the reactor dry, eliminating slurry preparation equipment and potential plugging issues.
- A CFB generally requires lower reagent feed rates resulting in lower operating costs and less solid waste.

The most significant drawback to a CFB is that the absorber vessels are typically limited to 150-200 MW; some vendors have smaller maximum vessel sizes while others are developing vessels large enough for 300 MW. Multiple vessels would be required, as many as four per unit depending on the vendor, adding to the cost and complexity of a CFB installation at Columbia. There are only a few large boiler installations operating with CFB FGD systems, and the experience base for CFB FGD systems operating on PRB coal-fired boilers is very limited. Additional drawbacks to the CFB system are:

- A CFB has a higher pressure drop across the absorber vessel, resulting in a greater parasitic load.
- The CFB is not flexible at handling varying unit loads, such as would be the case at Columbia. The CFB requires a minimum gas flow rate to maintain the fluidized nature of the bed. If the unit load drops below this minimum, a gas recycle system is required to maintain performance of the bed. The gas recycle can add significant expense and complexity to the system.
- The baghouse downstream of the CFB is typically designed with a lower air-to-cloth ratio resulting in a baghouse with a larger footprint than would be found downstream of an SDA. The operating temperature for the CFB is also

higher than that of the SDA, further increasing the size of the baghouse in the CFB case.
- The CFB system requires that the baghouse be elevated to recycle a portion of the dryer solids via airslide. This will increase the structural steel and foundation costs of the baghouse.
- There is no market for the beneficial reuse of the CFB byproduct mixture of calcium salts, unused reagent, and flyash.

B.4 Cost Comparison of FGD and Mercury Technologies

As shown in the previous sections, for an LSFO system to achieve 90% mercury reduction an ACI system and a baghouse are required. In addition, to limit the discharge of mercury contaminated LSFO wastewater, a ZLD system is also required. A dry FGD system consisting of an SDA, baghouse, and ACI system can achieve similar results. A cost comparison was performed for each group of technologies to determine the cost-effectiveness of each alternative. The CFB system was eliminated from consideration and therefore not included in this cost comparison due to its limits in vessel sizing, and limited operational experience on boilers similar in size to Columbia Units 1 and 2 and units that fire PRB coal.

The capital costs for the FGD equipment were developed based on a detailed cost estimate done in April 2008. This estimate was further refined by obtaining budgetary cost quotations from some of the major FGD system suppliers for the cost of their FGD equipment package, uninstalled, but including support steel and all necessary piping and electrical connections within the boundaries of their scope of supply. An engineering consultant then developed the installed Total Capital Requirement for the entire FGD system and its supporting equipment. Capital investment estimates were completed at this same level of detail for both wet (LSFO) and dry (SDA) FGD installations.

In addition to the capital cost estimates, the design criteria for the site were used as the basis calculating fixed and variable annual operating costs. The variable cost components are based on a series of material balance calculations that specify the expected rates of limestone or lime consumption, waste generation, and water and power consumption. These cost estimates were calculated using the EPRI IECCOST model, an industry standard for estimating costs for emissions control systems. The operating costs are summarized in Table B2 along with the variable consumption and production rates as calculated by the IECCOST model for the given operating conditions.

Table B1 summarizes the design criteria applied to the technologies evaluated for control of SO_2 and mercury emissions at Columbia Units 1 and 2. The analysis is based on burning the design coal, the highest sulfur coal currently considered for use at the site.

Table B1. Control Technology Design Criteria

Parameter	Design Criteria
Coal Sulfur Content (wt%)	0.78%
Wet FGD – LSFO	
Removal Efficiency	95%
Limestone Feed Rate	1.03 lbmol $CaCO_3$/lbmol SO_2 removed
Particulate Removal	Existing ESP
Dry FGD – SDA	
Removal Efficiency	90%
Recycle Included?	Yes
Baghouse Included?	Yes, Required
Lime Feed Rate	1.4 lbmol CaO/lbmol inlet SO_2
Mercury – ACI	
Removal Efficiency	
Upstream of an SDA and baghouse	90%
TOXECON I	85%
Upstream of a Cold-Side ESP[a]	56%
Upstream of a Hot-Side ESP	25%
Type of Activated Carbon	Treated/Halogenated
Mercury – Fuel Additive	
Post-Combustion Oxidized Mercury	75%
Capture of Oxidized Mercury in LSFO	90%

a. Assumes SO_3 injection; SO_3 potentially reduces the capability of carbon to remove mercury

Table B2. Columbia Units 1 and 2 Technology Selection Cost Comparison

	UNITS	LSFO+BH+ACI[a]	SDA+BH+ACI
Capital Costs			
Total Project Cost	$	$950,000,000	$627,000,000
	$/kW	$900	$600
Operating Parameters			
Reagent Usage	tons/hr	20.4	16.7
FGD Power Consumption	MW	20.4	16
BH/ACI Power Consumption	MW	7.5	Included in FGD
Total Water Usage[b]	gpm	1,260	995
Byproduct Production	tons/hr	34.5	33.0
Activated Carbon	lb/hr	910	910
Operating and Maintenance Costs			
Fixed O&M	$/year	$17,920,000	$10,780,000
Variable O&M	$/year	$9,530,000[c]	$29,440,000
Power Costs[d]	$/year	$7,720,000	$4,430,000
Levelized Capital Recovery	$/year	$115,420,000	$76,070,000
Total	$/year	$150,420,000	$120,720,000

a. Includes the cost of a new chimney
b. Includes both fresh water and blowdown/dilution water
c. Assumes that the gypsum byproduct is sold with no net revenue
d. Assumes $40/MWh cost of power

APPENDIX C

EGEAS SUMMARY REPORT

APPENDIX C | ATTACHMENT A

EGEAS SUMMARY REPORT | NON-CONFIDENTIAL TABLES

APPENDIX C | ATTACHMENT B

EGEAS SUMMARY REPORT | CONFIDENTIAL TABLES

APPENDIX D

PROJECT CONCEPTUAL DESIGN SCOPE ASSUMPTIONS

Appendix D Project Conceptual Design Scope Assumptions

General Project Estimate		
	Columbia Unit 1	*Columbia Unit 2*
Project Description	Retrofit SDA and baghouse to reduce SO_2 emissions and ACI upstream of the SDA and baghouse to reduce mercury emissions.	
Type of Plant	Utility grade reliability.	
Design Fuel	PRB coal (with highest anticipated sulfur content): 8,700 Btu/lb; 26% moisture, 9% ash, maximum 0.78% sulfur.	
Boiler Design Steam Pressure	2,620 psig	2,620 psig
Boiler Design Steam Temperature	1,005°F	1,005°F
Operation	Load Following with swings 250 - 550 Gross MW	Load Following with swings 250 - 550 Gross MW
Capacity Factor	80%	78%
Minimum Load Capacity	30%	30%
Project Location	Columbia Energy Center in Pardeeville, WI	
Site Description	Brownfield- existing Units 1 and 2 at the Columbia Energy Center	
Boiler Manufacturer	Alstom Power	Alstom Power
Project Commissioning and Start-up Date	1975	1978
Cost Basis/Assumptions		
General		
Lime Supply		
Source	Pebble lime from remote source TBD.	
Delivery	Pneumatic truck with positive displacement blower.	
Storage and Preparation	Lime storage silo and slaker; Lime day bins with lime feeder and slaker for each bin, and lime slurry tanks.	
Activated Carbon for ACI		
Source	Brominated activated carbon from remote source TBD.	
Delivery	Pneumatic truck with positive displacement blower.	
Storage and Preparation	ACI silo North of Unit 2 (constructed as part of Unit 2 system) expected for storage of carbon for Unit 1 and Unit 2.	
Scrubber Waste Disposal	Temporary day storage in FGD storage silos located west of SDA vessels. Transportation via pneumatic truck to landfill.	
Civil		
Site Conditions	Adequate space to support additional equipment, with constraints existing due to access of existing roads and placement of existing plant equipment.	
Soil Conditions/Stability	Soils are stable and require no further preparation in and around area suitable for use as laydown.	

Subsurface Rock	Rock exists in the area.
Construction Storm water Control	BMP will be employed during construction. Rainwater for the new area will be collected through catch basins and discharged to new storm water retention basin by gravity flow, and pumped to the ash pond.
Wetland Mitigation	No wetlands exist in the area of proposed construction.
Landscaping	Minimal landscaping is required. Disturbed areas will be seeded for erosion control.
Rail Access	Delivery of equipment, lime, and carbon reagents is expected to be by truck. Rail access is available; however, there is little spare capacity due to coal delivery.
Truck Access	Existing roads will be used for construction access. Temporary roads may also need to be used for transportation of equipment. All roads will be paved with asphalt.
Laydown Areas	Sufficient space is available north of the proposed location, in close proximity to the work area.
Structural	
Soil Bearing Capacity	Additional geotechnical information will be used to determine soil stability in specific areas of the project.
General Enclosures	The baghouse hoppers will be enclosed with a perimeter wall. SDA towers will be enclosed in a building, as well as recycle solids equipment (if applicable).
Platforms	Adequate platforms shall be provided to allow access to all components requiring routine maintenance.
Mechanical	
ID Fans	Two (2) ID booster fans per unit (four total), single speed axial fans with variable blade pitch flow control.
Pumps	Sparing philosophy includes 2x100% for most applications.
Compressed Air Supply	New air compressors will be provided to supply air required for the pulse jet baghouse.
Fire Protection	Fire protection shall be subject to review by local fire officials; currently includes tie-in to existing firewater system, existing controls and alarms systems.
Fire Detection	Fire detection will be included as required to initiate fire protection. Further, fire detection will be included in the electrical and control areas.
Emissions Control	
Emissions Control	
NOx	Existing combustion controls: Overfire Air and Low NOx burners. Current NOx limit is 0.7 lb/MMBtu 3-hr average; 0.45 lb/MMBtu annual average. Current emissions as measured over 2005 – 2007 are 0.142 lb/MMBtu (Unit 1) and 0.133 lb/MMBtu (Unit 2)
SOx	Current limit is 1.2 lb/MMBtu 3-hr average. Current emissions, as measured over 2005 – 2007 are 0.602 lb/MMBtu (Unit 1), and 0.625 lb/MMBtu (Unit 2).

Opacity	20% (Title V air permit)
Mercury	Installed ACI system for injection upstream of ESP on Unit 2. Expect to achieve 90% reduction on both Units by activated carbon injection upstream of SDA and baghouse. Current emissions (including native capture of ESPs) are 6.69 lb/TBtu (Unit 1), and 5.95 lb/TBtu (Unit 2).
Particulate	Currently operate ESPs on each unit. Particulate limit is 0.1 lb/MMBtu (Title V air permit). Planned installation of SDA and baghouses should not increase particulate emissions.
Electrical	
Auxiliary Power	Additional auxiliary power to FGD system shall be supplied from existing available plant power. A new motor control center for the FGD system is required, as well as two new redundant transformers.
Control System	DCS tie-in with existing plant system.
Plant Communications	Dial telephone systems will be provided. Page-party systems will also be provided at operating and maintenance locations, equipment rooms, and major control locations.
Construction	
Performance Testing	Included for all components regardless of contracting approach.
Stack Testing	As required to meet regulation.
Commissioning and Start-up	Included
Operator Training	Included
Construction Utilities	
Water Supply	Water supply for construction will be from existing water supply.
Construction Sanitary Facilities	Construction personnel sanitary facilities shall be portable facilities with wastes being removed and disposed of off-site via a portable vacuum truck.
Construction Power	Existing plant will provide construction power requirements.
Equipment Delivery	Equipment will be received via truck.
Construction Schedule	It is assumed that the construction schedule will be adequate to allow the project to be completed with minimal overtime. Construction schedule will be estimated as a 5x10 schedule to incentivize labor.
Construction Facilities	Facilities (buildings) built to support construction shall be mobile and removed after construction.
Existing Facilities	No relocation of existing facilities is anticipated at this time. Demolition plans discussed in Section 5.
Miscellaneous	
Permanent Plant Operating Spare Parts	Allowance included assuming some amount of spares.

APPENDIX E

GENERAL SO_2 REDUCTION TECHNOLOGY DESCRIPTIONS

Appendix E General SO_2 Reduction Technology Descriptions

E.1 Limestone Forced Oxidation System

E.1.1 Process Description

Limestone with forced oxidation (LSFO) is the primary technology used for wet flue gas desulfurization (FGD) systems with an excess of 80% of the market share. The process uses a limestone (also known as calcium carbonate, $CaCO_3$) reagent and is capable of removing 95%+ of the SO_2 present in the inlet flue gas.

In the LSFO process, hot flue gas exiting a new booster fan or an existing ID fans enters a large open cylindrical absorber vessel with several layers of spray nozzles at the top. The nozzles spray dilute limestone slurry, typically 15%-20% by weight suspended solids, counter to the flue gas flow through the vessel, allowing for the maximum contact between the flue gas and limestone for improved SO_2 reduction efficiency. The SO_2 in the flue gas reacts with the calcium carbonate in the limestone particles to form calcium sulfite ($CaSO_3$) according to the following reactions:

$$CaCO_3 + SO_2 + 1/2H_2O \rightarrow CaSO_3 \bullet 1/2H_2O + CO_2$$

The reacted slurry is collected in the absorber reaction tank (integral with the absorber vessel), where compressed air is introduced to force the completion of the reaction to calcium sulfate ($CaSO_4$, also known as gypsum) according to the following reactions:

$$CaSO_3 \bullet 1/2H_2O + 1/2O_2 + 3/2H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

This process alleviates problems such as gypsum scaling and dewatering difficulties. Some of the material is recycled back to the spray nozzles with fresh limestone slurry; the remaindered is removed from the reaction tank and processed to form a dry gypsum byproduct. The LSFO gypsum byproduct is salable as commercial-grade gypsum that can be used for wallboard manufacturing or other industrial applications. The scrubbed flue gas exits the top of the vessel through several layers of mist eliminators, which capture most of the fine aerosols. A process flow diagram for a typical LSFO system is shown in Figure E1.

A considerable amount of water is necessary for the LSFO process, primarily for the reagent slurry. The reagent slurry water cools the flue gas temperature from approximately 300^{o}F to approximately 130^{o}F, which results in a saturated flue gas. Water is also required to replace water lost with the byproduct solids, and blowdown streams used to control dissolved solids and fines. Makeup water can be supplied from any source that is not saturated with respect to any of the dissolved solids and contains a relatively low concentration of suspended solids. For example, cooling water tower blowdown is typically suitable for makeup to absorber. However, the mist eliminator wash stream, which serves as a large portion of the scrubber, should be higher quality (e.g. plant service water) in order to maintain scale-free operation.

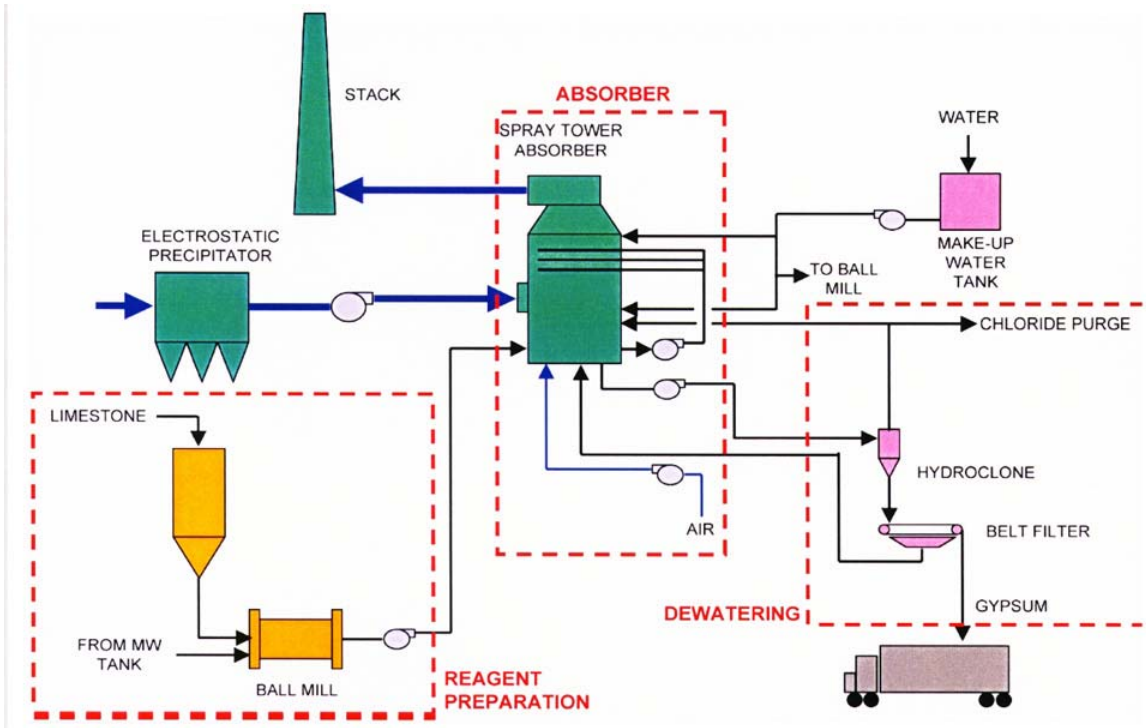


Figure E1. Typical LSFO Process Flow Diagram

There is considerably more equipment involved with wet scrubbers that results in greater space requirements and increased power consumption. This equipment includes limestone unloading and preparation equipment, reagent mixing equipment, slurry and recycle pumps, tanks, air compressors, vacuum filters, byproduct processing equipment and wastewater treatment systems. In addition, because the flue gas is saturated with moisture, the absorber vessel and all downstream components must be fabricated with corrosion resistant materials. The scrubber vessel and ductwork are usually fabricated of a specialty stainless steel and the chimney liner is usually fiberglass.

E.1.2 Reagent Preparation

Limestone from the bulk storage area is transferred to a local storage area by trucks or trains. The reclaim system includes a vibrating feeder and conveyor system to transfer limestone to day bins. Limestone day bins and feeders supply limestone to either horizontal or vertical type ball mills. The ball mills grind the limestone to 95 percent less than 325 mesh and use a wet recycle classification loop to ensure proper size distribution to the process. This particle size produces a large surface area for gas contact without excessive power consumption by the ball mill. The 30-35 percent solids slurry from the ball mill system is stored in limestone slurry tanks prior to transfer to the absorbers.

E.1.3 Byproduct Handling

The gypsum slurry removed from the absorber reaction tank is saturated with large dense gypsum crystals. The gypsum is separated from the water in a two step process. Hydroclones are used first to dewater the slurry to about 50 percent solids. This flow is directed to a secondary dewatering facility, which uses either rotary drum or vacuum belt filters. The cake coming off of the belt filter is typically a minimum 90 percent gypsum solids and less than 10 percent water. The rotary drum dryer will dewater the slurry to approximately 80% to 85% gypsum solids. The remaining liquid is returned to the scrubber reaction tank. If the gypsum is to be sold for industrial use (e.g. wallboard or cement manufacturing, agricultural use), a washing sequence is included in the vacuum filter design to reduce chloride content and eliminate contamination. The cake wash water is usually heated to promote drying to less than 10% moisture.

The gypsum from the vacuum belt filter is transferred by belt conveyor to a storage building until sold and transported off site.

E.1.4 Wastewater Treatment

Blowdown of a portion of the process water returned from the gypsum dewatering/washing process is necessary to control the concentrations of dissolved and suspended solids in the scrubber liquor as it concentrates due to the continuous recycle of scrubber slurry and evaporation of water into the flue gas. The blowdown stream is also used to control chloride levels in the absorber reaction tank and recycle system. The blowdown stream may also be used to purge fines, which tend to blind filter cloths, leading to difficulties in dewatering.

The quality of wastewater purge stream from the FGD process depends upon the sources of makeup water, the coal composition, and the byproduct specifications. Contaminants that may require removal could include trace heavy metals and chlorides. The standard FGD wastewater treatment (WWT) consists of a multi-stage physical/chemical treatment system consisting of precipitation, flocculation, and dewatering equipment to address mercury, iron, cadmium, and other contaminants. Generally, chlorides are not removed in a physical/chemical treatment system and are carried out with the WWT system discharge. The solids generated by these treatment systems have to be disposed of properly. The liquid stream can be used for coal pile wetting, ash sluicing, and/or combined with the plant cooling water discharge.

An alternative to a physical/chemical treatment system is zero liquid discharge (ZLD). ZLD can be used to remove dissolved solids and heavy metals, such as mercury, in addition to chlorides. A fully integrated ZLD system incorporates lime softening followed by a mechanical vapor compression brine concentrator and a steam driven forced circulation crystallizer and filter press system. The only ZLD installation in the United States was at AES Cayuga Station (formerly NYSEG's Miliken Station) as part of the Department of Energy's Clean Coal Demonstration Project. The evaporator system experienced numerous problems and did not work satisfactorily during the demonstration. Operational problems included plugging of the evaporator tubes and corrosion of various parts of the system. The system was subsequently abandoned. Modifications to the process used at the demonstration site have been suggested, but present challenges of their own, such as solids handling. Aquatech, a supplier of ZLD systems, has five installations at FGD sites in progress in Italy at various stages of construction and operation; the furthest along having several months of operating time. Until the technology has matured and some of the challenges of treating FGD wastewater are addressed, achieving zero-liquid discharge would be difficult. In addition, the systems are very expensive to install because of the materials of construction required to prevent corrosion. There is very little operating and maintenance data available, but it is expected that O&M costs would be very high until the technology matured and some of the challenges of treating FGD wastewater are addressed.

E.2 Spray Dryer Absorber System

E.2.1 Process Description

A spray dryer absorber (SDA) system is a semi-dry FGD system that can, based on industrial experience, consistently achieve +90% SO_2 removal. The SDA system is considered a semi-dry process because a liquid slurry reagent is used, however, the byproduct is a dry mixture of fly ash and reaction products. In the SDA process, the hot flue gas exiting the induced draft fan(s) enters the top of the spray dryer vessel. Within the vessel, atomized slurry of lime and recycled solids contact the flue gas stream. The sulfur oxides (SO_2 and SO_3) in the flue gas react with the lime and flyash alkali to form a mix of calcium salts, unreacted reagent, and flyash. The water entering with the slurry vaporizes, lowering the temperature and raising the moisture content of the scrubbed gas. The spray dryer outlet temperature is typically controlled within 30-35°F above the gas saturation temperature. A closer approach to the saturation temperature allows the SDA system to achieve higher removal efficiency, but risks condensation of water and buildup of wet solids on internal surfaces increasing the potential for corrosion and plugging of the gas path and filter bags.

The scrubbed gas and dry reaction products leave from the side or the bottom of the vessel. A particulate control device, typically a baghouse, downstream of the SDA vessel removes the dry solid reaction products, unreacted reagent, and flyash before the scrubbed gas is released to the atmosphere. The bags collect a layer of solids on their surfaces between cleanings, and the movement of the flue gas through this layer enhances the gas-solid contact whereby remaining SO_2 continues to react with the residual lime in the collected solids. As much as 25% of the total SO_2 removal can occur in the baghouse. A portion of the collected reaction product and flyash solids is recycled to the slurry feed system. The remaining solids are transported to a landfill for disposal.

The chemical reactions defining the SO_2 removal process as well as a process flow diagram for the spray dryer absorber system are given below.

Raw lime (CaO) is slaked with an excess of water to form a calcium hydroxide ($Ca(OH)_2$) slurry:

$$CaO + H_2O \rightarrow Ca(OH)_2$$

The sulfur oxides (SO_2 and SO_3) in the flue gas are absorbed into the slurry and react to form calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salt products:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet 1/2H_2O + 1/2H_2O$$

$$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

A fraction of the sulfite product may also be oxidized to the sulfate form by reaction with oxygen in the flue gas:

$$Ca(OH)_2 + SO_2 + 1/2O_2 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

Any HCl in the flue gas, present because of the chloride content of the fired coal, is also absorbed into the slurry and reacts with the slaked lime to for a dry salt byproduct:

$$Ca(OH)_2 + 2HCl \rightarrow CaCl_2 + 2H_2O$$

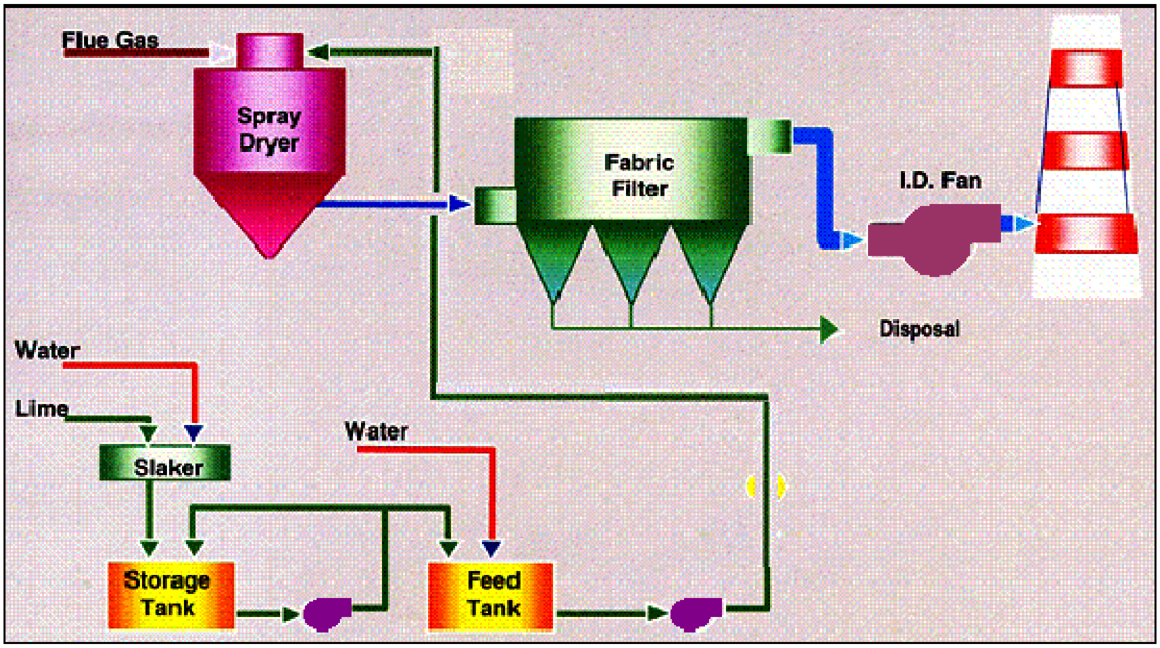


Figure E2. Typical SDA Process Flow Diagram

As the reactions above indicate, the SDA process is highly effective at controlling SO_3, which condenses with water vapor to form sulfuric acid. Over 90% of the sulfur trioxide that is formed during combustion is absorbed in the SDA vessel and baghouse. This eliminates the potential for plume opacity due to acid mist or acid corrosion in the downstream ductwork and particulate collection system.

The SDA system consists of less solids handling equipment then wet scrubber systems, requiring a lower power consumption. This equipment includes lime unloading and storage equipment, reagent slaking equipment, slurry pumps, tanks, rotary atomizer(s), and byproduct handling equipment. Additional equipment maybe required if a recycle system is incorporated with the SDA to increase reagent utilization. Because the flue gas is maintained above the saturation temperature throughout the process, the absorber vessel and all downstream components can be fabricated of carbon steel.

E.2.2 Reagent Preparation

The reagent used in a spray dryer absorber is lime in pebble form. The lime is transferred from bulk storage to a slaker. Fresh water is introduced to the slaker to hydrate the pebble lime and produce slurry that typically contains 19 wt% solids. A ball mill slaker pulverizes the inert material and maintains the inerts with the reagent slurry. If a detention or paste slaker is used, the grits are removed at the slaker for separate disposal. The slaked lime, $Ca(OH)_2$, flows to an agitated lime slurry feed tank. This slurry is then pumped to the spray dryer rotary atomizer where it is injected into the flue gas along with additional water to control the outlet temperature within 30-35°F above the gas saturation temperature.

E.2.3 Byproduct Handling

The spray dryer system produces a dry solid product consisting of calcium sulfite/sulfate, unused hydrated lime, and flyash. These dry solid products can be handled by conventional dry flyash handling systems. A portion of the collected reaction product and flyash solids may be recycled to the slurry feed system to increase reagent utilization and reduce cost; the remaining solids are sent via the dry solids conveying systems to a storage silo. From the silo they are trucked to a landfill for disposal. Because the reaction products are dry, there are no wastewater streams.

E.3 Circulating Fluidized Bed Absorption System

E.3.1 Process Description

The Circulating Fluid Bed Scrubber (CFB) process is a dry scrubbing technology that can consistently achieve ~94% SO_2 removal. The process is totally dry, meaning it not only produces a dry, free flowing disposal product but also introduces the lime reagent as a dry, free flowing powder. In the CFB process, flue gas enters the bottom of the fluidized bed reactor(s). As the flue gas enters the venturi-shaped entrance to each reactor, it is mixed with hydrated lime reagent and recycled flyash and reaction product solids. Water is injected into the reactor to cool and humidify the flue gas and assist in SO_2 removal. The flue gas outlet temperature is controlled to around 35^{o}F above the saturation temperature. The CFB reactor has a tall cylindrical configuration to allow adequate time for the reaction of the sulfur oxides (SO_2 and SO_3) in the flue gas with the reagent. The byproduct is a mixture of calcium salts, unreacted reagent, and flyash.

The spent solids and flyash are carried out of the top of the reactor and captured downstream by a baghouse or ESP. A portion of these combined solids are recycled to the fluidized bed absorber via air slides. The remaining material is transported to a disposal solids silo. The flyash and reaction products are drawn from the silo and conditioned in a pug mill(s) for disposal to landfill. A process flow diagram for CFB is shown in Figure E3 below.

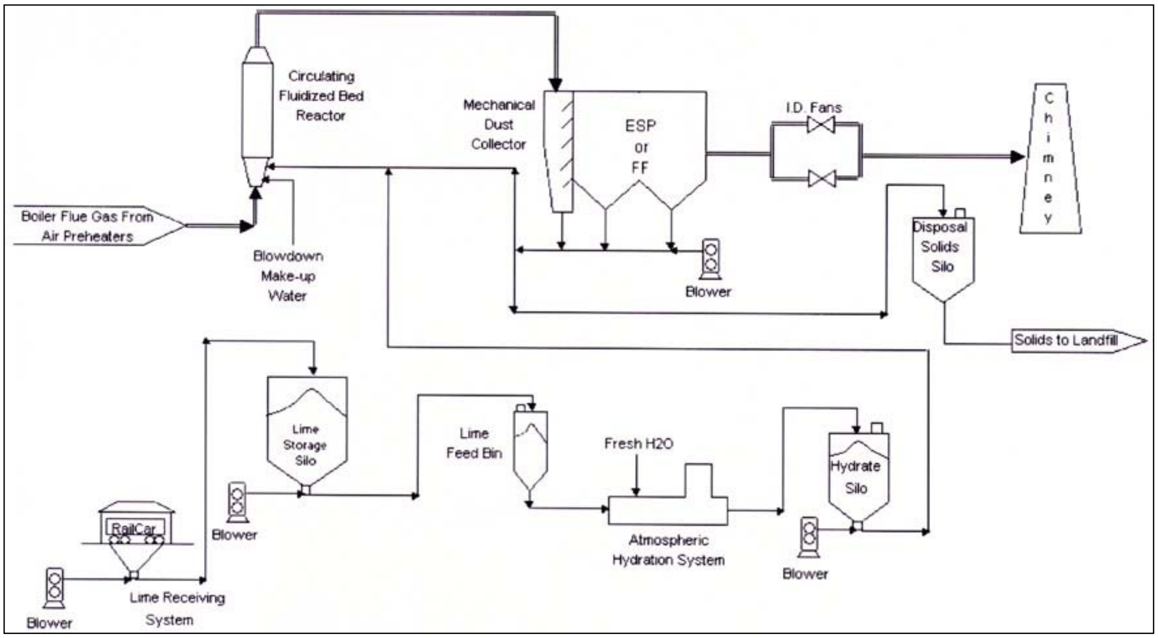


Figure E3. Typical CFB Process Flow Diagram

The CFB process chemical reactions are similar to that of the SDA, as shown below:

Lime Hydration:	$CaO + H_2O \rightarrow Ca(OH)_2$
SO_2 Reaction:	$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \,.1/2H_2O + ½\, H_2O$
SO_3 Reaction:	$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \,.\, 2H_2O$
Sulfite Oxidation:	$Ca(OH)_2 + SO_2 + H_2O\ 1/2O_2 \rightarrow CaSO_4 \,.\, 2H_2O$
HCl Reaction:	$Ca(OH)_2 + HCl \rightarrow CaCl_2 + 2H_2O$

E.3.2 Reagent Preparation

Pebble lime is transported pneumatically from the lime storage silos to the lime day bin which feeds the dry lime hydration plant. From the day bin, pebble lime is charged into a lime hydrating fluidized bed reactor. The pebble lime is hydrated by the injection of fresh water in the hydrating reactor in an amount proportional to the feed rate of the pebble lime. Hydrating water consumption is approximately 150% of the stoichiometric requirement. The highly reactive hydrated lime product, which is still considered to be a dry powder, is pneumatically transported to hydrated lime surge bins. The hydrated lime reagent is drawn from each hydrated lime surge bin by variable speed rotary feeders that transfer the hydrated lime to an airslide that conveys and feeds the hydrated lime into the associated scrubber tower.

E.3.3 Byproduct Handling

The flue gas exits the CFB reactors and is drawn through a baghouse. Hydrated lime and SO_2 reaction products are separated from the flue gas and collected with the flyash in the baghouse hoppers. The flyash and reaction solids are discharged from the hoppers and split into two streams. The first stream is recycled via an airslide and fed back into the lower section of the associated CFB reactor. The second stream is discharged through an airlock hopper and transported by a pneumatic pressure conveying system to a flyash/reaction products storage silo. The flyash and reaction products are gravity discharged from the silo into a pug mill. The pug mill conditions and discharges the ash and reaction products into ash dump trucks for transportation to a landfill.

APPENDIX F

GENERAL MERCURY REMOVAL TECHNOLOGY DESCRIPTIONS

Appendix F General Mercury Removal Technology Descriptions

F.1 Mercury Speciation

Mercury contained in coal vaporizes during the combustion process into two forms of mercury: elemental mercury (Hg^0) and oxidized mercury (Hg^{2+}). For PRB coals, such as those fired at Columbia Station, the elemental form of mercury dominates, accounting for 70% to 90% of the total mercury in the flue gas. The prevailing theory as to the dominance of elemental mercury is the fact that PRB coals contain low amounts of halogen elements, both chlorine and bromine, which aid in the oxidation of the mercury. The speciation of mercury in the flue gas is important because the oxidized form of mercury is easier to capture and remove than the elemental form, especially in a wet FGD system where the oxidized mercury is water soluble.

F.2 Activated Carbon Injection

The activated carbon injection process it the only mercury control technology that is considered commercially available with demonstration projects operated for extended periods at coal-fired utility boilers. Injection of carbon upstream of an existing ESP or baghouse has been tested at full-scale on a number of units.

Mercury removal demonstrated upstream of an ESP varied from 50% to 80% at activated carbon injection rates of 5-10 lb/MMACF but limited field tests have shown up to 90% removal with Brominated PAC (BPAC) at injection rates of 3-5 lb/MMACF for cold-side ESPs. Limited test results from hot-side ESPs utilizing Hot PAC (HPAC – carbon specially formulated for the hot-side environment) have shown mercury removal rates of 50-65%. The long term removal efficacy of ACI upstream of an ESP may be slightly lower depending on the injection location due to reduced contact time between the carbon and the flue gas prior to carbon collection in the ESP. ACI upstream of an ESP could also result in increased particulate emissions due to the increased grain loading to the ESP and the potential for reentrainment of carbon particles. The activated carbon is expected to collect on the ESP plates, and then drop into the collection hoppers located under the ESP. This arrangement may prevent the beneficial reuse of flyash due to the increased carbon content. The injection grid for activated carbon would be installed in the ductwork upstream of the ESP; additional equipment includes activated carbon receiving, storage and transfer system.

When sorbent injection is combined with a Compact Hybrid Particulate Collector (COHPAC), essentially a small pulse jet baghouse, the technology has been given the name TOXECON, a system configuration currently patented by the Electric Power Research Institute (EPRI). Carbon injection upstream of an existing baghouse or one installed as part of an SDA system is the same basic concept as TOXECON. Carbon injection upstream of the SDA vessel may result in mercury removal efficiencies greater than that of TOXECON due to the increased contact time between the carbon and flue gas.

F.2.1 TOXECON I

The TOXECON I system, ACI upstream of a COHPAC baghouse, has seen the most field-testing and forms the basis for the commercial offering by one vendor. Figure F1 provides a flow diagram for the TOXECON I system. The major components of the TOXECON I design include a pneumatic transfer system for connection to trucks delivering the activated carbon. The pneumatic piping transfers the activated carbon to the storage silo(s) that are equipped with a vent filter and weigh feeders. The feeders transfer the activated carbon to the pneumatic feed lines that move the AC to the injection location.

An injection grid is fed by a stream splitter that transfers the activated carbon to multiple injection lances feeding the injection grid installed in the ductwork. The solids are then collected in a downstream COHPAC baghouse. This baghouse will add 8-10" w.g. pressure drop to the flue gas at a typical filtering velocity of 4-6 feet per minute. The filter media collects the activated carbon solids from the flue gas and provides additional contact time for removal of the mercury. The solids are periodically removed from the baghouse and pneumatically transferred to a separate silo for ultimate loading onto trucks sent to a landfill. In this case, only trace quantities of flyash would be expected in the carbon sent to a landfill. Testing to date indicates that mercury adsorbed in activated carbon will not leach out into the groundwater. However, the EPA has not made any formal rulings on the hazards associated with carbon bound mercury.

This system has shown mercury removal capabilities in excess of 90% when utilizing activated carbon (plain and treated). However, long-term results show an average of 85% reduction in mercury levels from the inlet flue gas concentration.

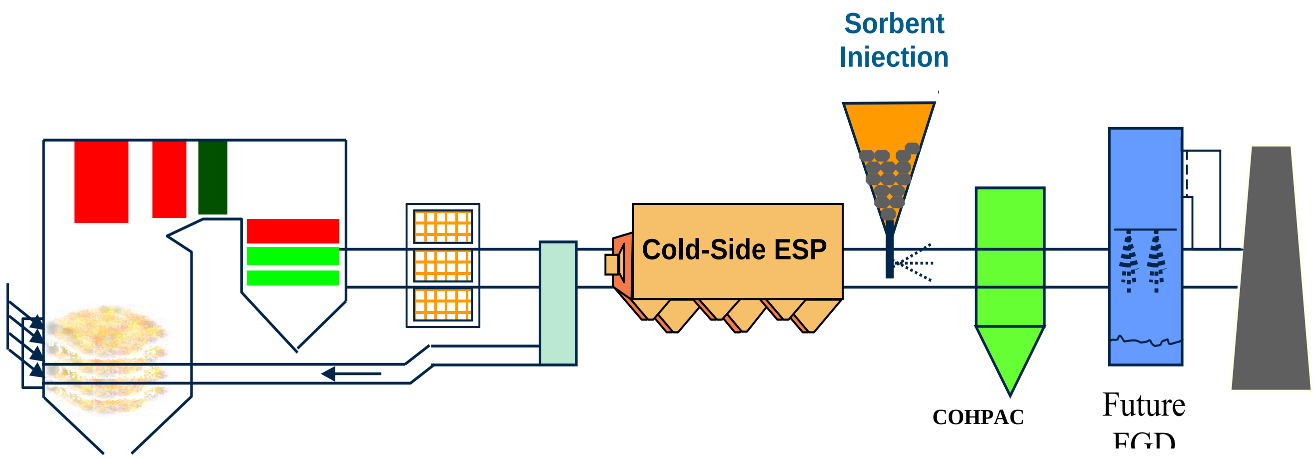


Figure F1. TOXECON I Arrangement

F.3 Sorbents

Sorbents used in a majority of mercury control demonstration projects include plain (powdered) and treated (brominated/halogenated) activated carbons. Both sorbents have test data showing 50-90% mercury removal with injection rates ranging from 2-10 lb/MMACF. The injection of AC will also contaminate the flyash unless the ash is removed upstream of the injection grid; this can make the flyash unmarketable for some applications, most notably as a concrete additive.

F.3.1 Plain Activated Carbon

Plain (untreated) activated carbon is commercially available from multiple vendors. This is the only system on the market today that has been demonstrated on multiple full-scale installations on a variety of coals and for extended test periods. These activated carbons are capable of achieving 90% mercury removal with a baghouse, but at injection rates sometimes approaching 10 lb/MMACF. Performance varies between the carbon suppliers.

Plain activated carbon is commercially available from multiple sources both domestically and internationally. This type of activated carbon is mass-produced for commercial applications other than mercury control for coal fired power plants.

F.3.2 Halogenated Activated Carbon

Treated activated carbon is produced by adding bromine, iodine or fluorine to the carbon to increase its ability to capture mercury. Field testing with halogenated activated carbons indicates that they can achieve 90+% mercury removal at injection rates of 3 lb/MMACF or less. The trade off is that treated activated carbons cost more than untreated carbon, but with increased production capacity projected as more carbon injections systems go on-line, the price of treated carbon is expected to drop.

Sorbent names include BPAC from Sorbent Technologies and Darco Hg-LH from Norit Americas, both treated with bromine. Sorbent Technologies is also developing an activated carbon sorbent that will have little to no effect on concrete production (CPAC).

F.4 Coal Pre-Treatment/Wet FGD Co-Benefit

This concept involves oxidizing elemental mercury with small amounts of a halogen added to the boiler and then capturing the oxidized mercury by conventional SO_2 control devices. The presence of chlorine and/or bromine promotes the oxidation of mercury, and oxidized mercury is readily removed across a wet FGD system. Calcium chloride and calcium bromide injection into the furnace have been tested on a limited scale on plants burning PRB, as well as North Dakota and Texas lignites.

The test results to date have increased the mercury removal across the wet FGD systems from a baseline of 45-55% to 73-81% with halogen injection. Testing to date has been for short durations and long-term balance-of-plant impacts have not been determined. Further testing is planned and EPRI is looking for expanded project participation.

The injection of bromine and bromide compounds into the boiler, flue gases, or onto the coal prior to combustion for enhancing mercury oxidation and removal is a concept patented by Dr. Bernhard Vosteen et al (US Patent 6,878,358) and exclusively licensed to Alstom Power and marketed as KNx™. This technology has undergone short-term field testing at units firing PRB coals with various combinations of emissions control equipment. When coupled with ACI or high natural unburned carbon levels, this technology has achieved short-term mercury removal rates of up to 94% combined across the particulate control device and FGD system.

Other developers are also attempting to pursue systems, including the ISCA Company, which claims to hold patents on the injection of chlorine or chlorine compounds into flue gas to oxidize elemental mercury upstream of an FGD system. In addition, Chem-Mod LLC has recently announced that it has developed a series of coal additives that reduce mercury emissions through oxidation and subsequent collection in other control equipment.

F.5 Chemical Additives to Control Mercury Re-emission from FGD Slurry

Testing is being conducted to evaluate the use of additives in wet lime or limestone FGD systems to prevent oxidized mercury from being reduced and subsequently re-emitted from the FGD absorber as elemental mercury. Reducing or eliminating the amount of mercury that is re-emitted from the FGD system will increase the overall collection efficiency of the system.

Testing is being conducted at three sites that burn: (1) Texas lignite, (2) a low-sulfur bituminous coal, and (3) a high-sulfur bituminous coal. There are no test results to report at this time.

Both Babcock &Wilcox and URS Corporation have completed field-testing of these chemical additives to reduce the vapor pressure of mercury over the scrubber slurry. Mitsubishi Heavy Industries is promoting its development of an oxidation/sulfite control system that will control the potential for mercury re-emission by ensuring that sulfite concentrations are maintained in the proper range.

APPENDIX G

LETTER TO PSCW FOR ACI INSTALLATION ON COLUMBIA UNIT 2

Appendix G Letter to PSCW for ACI Installation on Columbia Unit 2

PSC REF#:92620

Public Service Commission of Wisconsin
RECEIVED: 04/11/08, 10:46:51 AM

ALLIANT ENERGY

Wisconsin Power and Light Co.
An Alliant Energy Company

Corporate Headquarters
4902 North Biltmore Lane
P.O. Box 77007
Madison, WI 53707-1007

Office: 1.800.862.6222
www.alliantenergy.com

April 11, 2008

Ms. Sandra J. Paske
Secretary to the Commission
Public Service Commission of Wisconsin
PO Box 7584
Madison, WI 53707-7854

Re: Installation of Activated Carbon Injection Control Equipment on Unit #2 at the Columbia Generating Station, Columbia County, Wisconsin

Dear Ms. Paske,

This letter serves as formal notification that Wisconsin Power and Light Company (WPL) is altering its plan to install a mercury control system on Columbia Generating Station Unit 2. Rather than the Sorbent Injection (MinPlus) system that was originally planned for this unit, an Activated Carbon Injection (ACI) system will be installed instead. This technology employs a powder activated carbon that is injected into the flue gas stream before the electrostatic precipitator. The activated carbon absorbs the flue gas mercury, which is removed when the mercury laden carbon particles are captured in the electrostatic precipitator.

As highlighted in the WPL letter filed with commission staff on November 16, 2007 (PSC REF# 85893, page 4, section 2.2.2), an ACI system was identified as the back-up mercury control solution for Columbia Unit 2 and this alternative is being pursued for the following reasons:

- Mobotec/MinPlus was purchased by Nalco in December 2007 and Nalco retracted previously communicated MinPlus performance guarantee commitments until it could further test the product.
- WPL has completed preliminary pilot testing of the ACI technology at Edgewater Unit 5 (PSC REF# 85893, page 4, section 2.2) and the early results are encouraging.

This change in technology impacts the previously forecasted completion date for this project. The revised in-service and operational date planned for this ACI system is January 2009. WPL continues to estimate that this project will cost less than the threshold amount established by the Public Service Commission of Wisconsin that would trigger the need for a Certificate of Authority filing.

This technology selection change is being filed in the interest of clarifying WPL's previous communication on the status and timing of this project.

Please contact me at (608) 458-3924 if you have any questions regarding this project.

Sincerely,

/s/ Scott R. Smith
Scott R. Smith
Regional Manager, Regulatory Affairs

cc: Scot Cullen

APPENDIX H

WDNR COLUMBIA “SUBJECT TO BART” NOTIFICATION LETTER

Public Version

Appendix H WDNR Columbia "Subject to BART" Notification Letter

State of Wisconsin \ DEPARTMENT OF NATURAL RESOURCES

WISCONSIN DEPT. OF NATURAL RESOURCES

Jim Doyle, Governor
Matthew J. Frank, Secretary

101 S. Webster St.
Box 7921
Madison, Wisconsin 53707-7921
Telephone 608-266-2621
FAX 608-267-3579
TTY Access via relay - 711

July 9, 2008

WP&L - Columbia Energy Center
Attn.: Mr. Jerald Lokenvitz, Plant Manager
W8375 Murray Road
Pardeeville, WI 53954

Subject: Notification regarding sources subject to BART

Dear Mr. Lokenvitz

Pursuant to ch. NR 433, Wis. Adm. Code, the Department is providing you this written notice of the Department's determination that your facility includes at least one source subject to BART (Best Available Retrofit Technology). You are required to conduct and submit to the Department an engineering analysis for the determination of the BART requirements for the sources subject to BART at your facility by **January 05, 2009.**

Federal regulations require all states, including Wisconsin, to develop State Implementation Plans to address visibility impairment in mandatory Class I Federal Areas. One of the provisions of the federal regulations is the application of BART requirements on certain existing stationary sources which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area. These sources are subject to BART and the BART requirements need to be determined on a site-specific basis.

The state of Wisconsin adopted a BART rule, ch. NR 433, Wis. Adm. Code, to establish the procedure for the BART determination. The rule has been effective since July 1, 2008. According to the BART rule, the department is required to provide written notice to the owner or operator of each facility which the department has determined includes a source that is subject to BART. No later than 180 days after the department sends the notification, the owner or operator of the source shall conduct and submit to the department a BART analysis for all emissions units which comprise the BART-eligible source.

In accordance with NR 433.03(04), Wis. Adm. Code, we are providing you with this notice that the department has identified one or more emission units at your facility that are subject to BART. The attached information shows the emission units subject to BART at your facility. You are required to conduct and submit to the department a BART analysis for all emission units which comprise the BART-eligible source at your facility by January 05, 2009. The department may grant an extension of up to 60 days to the submittal deadline if you submit a written request for an extension prior to January 05, 2009

We are looking forward to your cooperation in determining BART for the emissions units at your facility. Please contact Bob Lopez at 608 / 267-5284 or robert.lopez@wisconsin.gov if you need further clarification

Best Regards

Larry H. Bruss

Larry Bruss
Chief - Regional Pollutant & Mobile Source Section

cc: Bob Lopez / WDNR

dnr.wi.gov
wisconsin.gov